Guideline for the Framework Regulations

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Summary of Changes		
Date Revised	Sections (if applicable)	Description of Change

Foreword

The Canada-Nova Scotia Offshore Petroleum Board and Canada-Newfoundland and Labrador Offshore Petroleum Board (the *Regulators*) have issued this Guideline to provide clarity to those with statutory responsibilities in the offshore petroleum industry on the *Canada-Newfoundland and Labrador* and the *Canada-Nova Scotia Offshore Area Petroleum Operations Framework Regulations (Framework Regulations)* under Part III of the *Atlantic Accord Implementation Acts* (*Accord Acts*). This Guideline applies to all petroleum operations conducted in the *Offshore Area* to which Part III of the *Accord Acts* and the *Framework Regulations* apply. This Guideline also provides direction on the *Regulator*'s interpretation of the regulations.

Guidelines are developed to provide assistance to those with statutory responsibilities (including operators, employers, employees, supervisors, providers of services, suppliers, etc.) under the *Accord Acts* and regulations. Guidelines provide an understanding of how legislative requirements can be met. In certain cases, the goals, objectives and requirements of the legislation are such that no guidance is necessary. In other instances, guidelines will identify a way in which regulatory compliance can be achieved.

The authority to issue Guidelines and Interpretation Notes with respect to legislation is specified by sections 151.1 and 205.067 of the *Canada-Newfoundland and Labrador Atlantic Accord Implementation Act*, S.C. 1987, c.3 (C-NLAAIA), sections 147 and 201.64 of the *Canada-Newfoundland and Labrador Atlantic Accord Implementation Newfoundland and Labrador Act,* RSNL 1990 c. C-2, subsection 156(1) and section 210.068 of the *Canada-Nova Scotia Offshore Petroleum Resources Accord Implementation Act, S.C. 1988, c.28 (CNSOPRAIA)* and section 148 and subsection 202BQ(1) of the *Canada-Nova Scotia Offshore Petroleum Resources Accord Implementation (Nova Scotia) Act.* The *Accord Acts* also state that Guidelines and Interpretation Notes are not deemed to be statutory instruments.

For the purposes of this Guideline, these Acts are referred to collectively as the *Accord Acts*. Any references to the C-NLAAIA, the CNSOPRAIA or to the regulations in this Guideline are to the federal versions of the *Accord Acts* and the associated regulations.

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1.0 Acronyms and Abbreviations

2D/3D	Two and Three Dimensional
ABS	American Bureau of Shipping
AC-SBV-DOC	Atlantic Canada Standby Vessel Document of Compliance
ACW	Approval to Alter the Condition of a Well
ADW	Approval to Drill a Well
AGC	Automatic Gain Control
AIS	Automatic Identification Service
ALARA	As Low as Reasonably Achievable
ALARP	As Low as Reasonably Practicable
API	American Petroleum Institute
ASME	American Society of Mechanical Engineers
ASV	Annular Safety Valve
AVO	Amplitude versus Offset
BOP	Blowout Preventer
CA	Certifying Authority
CAOEC	Canadian Association of Energy Contractors
CAPP	Canadian Association of Petroleum Producers
CCG	Canadian Coast Guard
CCO	Chief Conservation Officer
CDP	Common Depth Point
CEAA	*Canadian Environmental Assessment Act, 2012* (S.C. 2012, c. 19, s. 52)
CER	Canada Energy Regulator
CIS	Canadian Ice Service

C-NLAAIA[1]	*Canada-Newfoundland and Labrador Atlantic Accord Implementation Act*
C-NLOPB	Canada-Newfoundland and Labrador Offshore Petroleum Board
CNSOPB	Canada-Nova Scotia Offshore Petroleum Board
CNSOPRAIA[2]	*Canada-Nova Scotia Offshore Petroleum Resources Accord Implementation Act*
CO	Carbon Monoxide
CO_2	Carbon Dioxide
COF	Certificate of Fitness
COP	Code of Practice
CPT	Cone Penetration Test
CSA	Canadian Standards Association
CSEM	Controlled-Source Electromagnetic
CSO	Chief Safety Officer
DFO	Fisheries and Oceans Canada
DHSV	Downhole Safety Valve
DHTV	Downhole Test Valve
DNV	Det Norske Veritas
DOF	Declaration of Fitness
DP	Dynamic Positioning
ECCC	Environment and Climate Change Canada
EMOBF	Enhanced Mineral Oil Based Fluid
FDAP	Field Data Acquisition Program
FIT	Formation Integrity Test
FLOT	Formation Leak-Off Test

[1] References to the C-NLAAIA in this Guideline are to the federal version of the *Accord Acts*
[2] References to the CNSOPRAIA in this Guideline are to the federal version of the *Accord Acts*

FMEA	Failure Mode and Effects Analysis
FMECA	Failure Mode, Effects and Criticality Analysis
FPSO	Floating Production, Storage and Offloading facility
FRC	Fast Rescue Craft
FRP	Fibre Reinforced Plastic
FSO	Floating Storage and Offloading facility
GBS	Gravity Based Structure
GGE	Geoscientific, Geotechnical and Environmental
GPS	Global Positioning System
GRE	Glass Reinforced Epoxy
GRP	Glass Reinforced Plastic
H_2S	Hydrogen Sulfide
HPHT	High Pressure High Temperature
HR	High Resolution
HSE	Health, Safety and Environment
IAA	*Impact Assessment Act* (S.C. 2019, c. 28, s. 1)
IAAC	Impact Assessment Agency of Canada
IACS	International Association of Classification Societies
IADC	International Association of Drilling Contractors
IATA	International Air Transport Association
ICAO	International Civil Aviation Organization
ICS	International Chamber of Shipping
IEC	International Electrotechnical Commission
IECEx	International Electrotechnical Commission System for Certification to Standards Relating to Equipment for Use in Explosive Atmospheres

IMCA	International Marine Contractors Association
IMDG	*International Maritime Dangerous Goods Code*
IMO	International Maritime Organization
IOGP	International Association of Oil and Gas Producers
IPTT	Interval Pressure Transient Testing
IS	Intact Stability
ISEDC	Innovation, Science and Economic Development Canada
ISM	International Safety Management
ISO	International Organization for Standardization
ISPS	*International Ship and Port Facility Security Code*
IWCF	International Well Control Forum
LEL	Lower Explosive Limit
LR	Lloyd’s Register
LRFD	Load and Resistance Factor Design
LSA	Life-Saving Appliance
LWD	Logging While Drilling
MARPOL	*International Convention for the Prevention of Pollution from Ships*
MD	Measured Depth
MODU	Mobile Offshore Drilling Unit
MOU	Memorandum of Understanding
MPD	Managed Pressure Drilling
MSC	Meteorological Service of Canada
MSL	Mean Sea Level
MVO	Magnitude versus Offset

MWD	Measurement While Drilling
MWE	Mud Weight Equivalent
NACE	National Association of Corrosion Engineers
NAD	North American Datum
NAF	Non-Aqueous Fluid
NAVCAN	NAV Canada
NDE	Non-Destructive Examination
NFPA	National Fire Protection Association
NL	Newfoundland and Labrador
NS	Nova Scotia
OA	Operations Authorization
OBF	Oil-Based Fluid
OIM	Offshore Installation Manager
OHS	Occupational Health and Safety
POB	Persons on Board
PPDT	Pore Pressure Dissipation Test
PPE	Personal Protective Equipment
PrOD	Preferred Orientation and Displacement
PSDM	Pre-Stack Depth Migration
PSTM	Pre-Stack Time Migration
PSV	Pressure Safety Valve
PVO	Phase versus Offset
RCMP	Royal Canadian Mounted Police
RMS	Root Mean Square

ROV	Remotely Operated Vehicle
RPAS	Remotely Piloted Aircraft System
RQ	Regulatory Query
RT	Rotary Table
SBF	Synthetic-Based Fluid
SBP	Sub-bottom Profiler
SCBA	Self-Contained Breathing Apparatus
SCPT	Seismic Cone Penetration Test
SCSSV	Surface Controlled Subsurface Safety Valve
SEG-Y	File format developed by Society of Exploration Geophysicists for storing geophysical data
SF	Seafloor
SFTP	Secure File Transfer Protocol
SIMOPS	Simultaneous Operations
SOLAS	*International Convention for the Safety of Life at Sea*
SP	Shotpoint
SSTT	Subsea Test Tree
SSV	Subsurface Safety Valve
TEMPSC	Totally Enclosed Motor Propelled Survival Craft
TLP	Tension Leg Platform
TQOP	*Atlantic Canada Offshore Petroleum Code of Practice for the Training and Qualifications of Offshore Personnel*
TVD	True Vertical Depth
UNCLOS	*United Nations Convention on the Law of the Sea*
VHF	Very High Frequency

VMC	Visual Meteorological Conditions
VSP	Vertical Seismic Profile
WBF	Water-Based Fluid
WDAP	Well Data Acquisition Program
WMO	World Meteorological Organization

2.0 Definitions

In this Guideline, the terms such as “authorization”, “chief safety officer”, “chief conservation officer”, “debris”, “delineation well”, “development well”, “employee”, “employer”, “exploratory well”, “extended formation flow test”, “field”, “gas”, “geological work”, “geophysical work”, “geotechnical work”, “hazardous substance”, “marine installation or structure”, “oil”, “operator”, “passenger craft”, “person”, “personal protective equipment”, “petroleum”, “pool”, “providers of services”, “significant discovery”, “spill”, “spill-treating agent”, “supervisor”, “supplier”, “waste”, “well”, “well termination date”, “workplace” and “workplace committee” referenced herein have the same meaning as in the *Accord Acts*.[3]

In this Guideline, the terms such as “confined space”, “hot work”, “materials handling equipment” and “safety data sheet”, referenced herein have the same meaning as in the *OHS Regulations*.

For this Guideline, the following definitions have been capitalized and italicized throughout. The following definitions apply:

Accord Acts	means the *Canada-Newfoundland Atlantic Accord Implementation Act, Canada-Newfoundland and Labrador Atlantic Accord Implementation (Newfoundland and Labrador) Act, Canada-Nova Scotia Offshore Petroleum Resources Accord Implementation Act* and *Canada-Nova Scotia Offshore Petroleum Resources Accord Implementation (Nova Scotia) Act*
Declaration of Fitness	means the “declaration” under Part III of the *Accord Acts*
Development Plan	means a *“development plan”* as defined in Part III of the *Accord Acts*

[3] C-NLAAIA 2, 47, 119, 135, 205.001(1); CNSOPRAIA 2, 49, 122, 138, 210.001(1)

Framework Regulations	means the *Canada-Newfoundland and Labrador Offshore Area Petroleum Operations Framework Regulations*, SOR/2024-25 and the *Canada-Nova Scotia Offshore Area Petroleum Operations Framework Regulations*, SOR/2024-26
Good Oilfield Practices	means those practices, methods, standards and procedures generally accepted and followed by prudent, diligent, skilled and experienced persons in petroleum exploration, development and production operations
Offshore Area	means the offshore area as defined by the *Accord Acts*
OHS Regulations	means the *Canada-Newfoundland and Labrador Offshore Area Occupational Health and Safety Regulations*, SOR/2021-247 and the *Canada-Nova Scotia Offshore Area Occupational Health and Safety Regulations*, SOR/2021-248
Regulator	means the Canada-Newfoundland and Labrador Offshore Petroleum Board or the Canada-Nova Scotia Offshore Petroleum Board, as the case may be

Additional notes on the use of this Guideline are as follows:

2.1 Guidance navigation

This document has been structured to provide guidance by Parts and sections of the *Framework Regulations*. The legislative requirement of the regulation appears in *italic*, **bold** font and the guidance is provided immediately after each applicable Part or section of the regulation, separated by double lines. This Guideline provides references to the *Accord Acts* and other applicable legislation and references to other regulatory instruments issued by the *Regulators*, and lists relevant standards and other items which should be considered. As numerical references to like legislative requirements found in both the C-NLAAIA and the CNSOPRAIA often differ slightly, where a pinpoint citation to a section or part thereof in the *Accord Acts* is included in the main body of this Guideline, the first pinpoint refers to the C-NLAAIA, and the second pinpoint found in parenthesis refers to the pinpoint in the CNSOPRAIA.

2.2 Use of the term “including”

When the term “including” is used in the *Accord Acts*, the *Framework Regulations* or this Guideline, it is implied that the list which follows is not exhaustive.

2.3 Equivalencies and Exemptions Process

When the applicant proposes to meet the requirements of a regulatory provision in a manner other than as prescribed in the *Framework Regulations*, an application for equivalency or exemption, via the RQ process, must be submitted to the *Regulator*. Guidance on the RQ process is provided on the *Regulators'* respective websites[4].

2.4 Codes of Practice

The occupational health and safety provisions set out in Part III.1 of the *Accord Acts*[5] provide authority for the CSO to require and approve a COP. A COP is a set of written rules respecting OHS established by either the operator or the employer or by the CSO for operators and employers to adopt. COPs are approved by the CSO and contain information in respect of OHS. The CSO can also revise a COP they impose, or they may require an operator or employer to revise a COP it has established for itself. All COPs in force are provided on the *Regulator*s' respective websites[6] and are referenced, as applicable, throughout this Guideline. A summary of all COPs referenced in this Guideline is provided in the Bibliography.

2.5 Flag State and Classification Society Rules

Although flag state and classification society rules may include similar requirements, the *Accord Acts* and *Framework Regulations* must be complied with regardless of any exemptions that have been granted from flag state or the classification society. Refer to section 153 of the *Framework Regulations* and this Guideline for additional guidance on decisions and exemptions.

3.0 Purpose and Scope

The purpose of this Guideline is to provide clarity to operators, employers and others with statutory responsibilities in the *Accord Acts* or the *Framework Regulations*. This Guideline applies to all petroleum operations in the *Offshore Area*. Although sections of the *Accord Acts* and the *Framework Regulations* may be referenced in the Guidelines, the onus is on those with statutory responsibilities to refer to the *Accord Acts,* the *OHS Regulations* and the *Framework Regulations* for the requirements, using this Guideline for guidance only.

[4] C-NLOPB – www.cnlopb.ca; CNSOPB – www.cnsopb.ns.ca
[5] C-NLAAIA 205.016, 205.021; CNSOPRAIA 210.016, 210.021
[6] C-NLOPB – www.cnlopb.ca; CNSOPB – www.cnsopb.ns.ca

4.0 Guideline

PART 1: GENERAL

Section 1 - Definitions

1 The following definitions apply in these Regulations.

accidental event means an unexpected or unplanned event or circumstance or series of unexpected or unplanned events or circumstances that may lead to the loss of life or damage to the environment, including pollution.

accommodations area means the area of an installation or vessel that contains the sleeping quarters, dining areas, food preparation areas, general recreation areas, offices and medical rooms and includes all washrooms in that area.

accommodations installation means an installation that is used to accommodate persons at a production site, drill site or dive site and that functions independently of a production installation, drilling installation or diving installation.

Act means the Canada–Newfoundland and Labrador Atlantic Accord Implementation Act (or the Canada-Nova Scotia Offshore Petroleum Resources Accord Implementation Act).

authorization means an authorization issued by the Board under paragraph 138(1)(b) (or 142(1)(b)) of the Act.

authorized inspector means a person who is recognized under the laws of Canada or of a province as qualified to inspect boilers and pressure systems or a representative of a certifying authority who is qualified to carry out that function.

barrier element means a physical element that on its own does not prevent the flow of fluids but that in combination with other physical elements forms a well barrier.

barrier envelope means an envelope consisting of a set of barrier elements that prevents any unintended flow of fluids from the formation into the well-bore, another formation or the environment.

certificate of fitness means a certificate referred to in section 139.2 (or 143.2) of the Act.

certifying authority means the American Bureau of Shipping, Bureau Veritas, Det norske Veritas or Lloyd's Register.

***classification society** means a member of the International Association of Classification Societies that has recognized and relevant competence and experience in, and established rules and procedures for, the classification of fixed and floating structures, including vessels, that are used in oil or gas activities in locations with physical and environmental conditions similar to those of the offshore area.*

***commingled production** means the production of petroleum from more than one pool or zone through a common well where the production from each pool or zone is not measured separately.*

***completion interval** means a section within a well that is prepared to permit*
(a) the production of fluids from the well;
(b) the observation of the performance of the reservoir; or
(c) the injection of fluids into the well.

***control centre** means a continuously staffed work area in which a control system that is critical to the operation of an installation or a pipeline, to safety or to the prevention of waste and pollution is located.*

***control system** means any system, station or panel used to monitor the status and control the operation of equipment used for or in support of the drilling for, or the production, processing or transportation of, petroleum or any system, station or panel used to monitor and control the operation of an installation.*

***decommissioning and abandonment** means the carrying out of the following processes in accordance with any applicable Act of Parliament, any applicable regulation made under an Act of Parliament, the applicable authorization and any approved development plans:*
(a) the cessation of operations;
(b) the controlled abandonment of all wells;
(c) the retirement from service and abandonment or removal of all installations, including their systems and equipment; and
(d) the retirement from service and abandonment or removal of all pipelines and materials.

***delineation well** has the same meaning as in subsection 119(1) (or 122(1)) of the Act.*

***development well** has the same meaning as in subsection 119(1) (or 122(1)) of the Act.*

***diving installation** means an installation or vessel on which a diving system is installed.*

***diving project** means any work or activity that is related to the exploration or drilling for, or the production, conservation, processing or transportation of, petroleum and that involves diving.*

***diving system** means the equipment that is required to execute a dive, including that required for compression, decompression, rescue and recovery.*

***drilling installation** means a drilling unit or a drilling rig, and the stable foundation on which it is installed — including an artificial island, an ice platform, a floating platform, a platform fixed to the seabed and any other foundation specifically used for drilling — and any associated accommodations area.*

***drilling program** means a program for the drilling of one or more wells within a specified time and within specified areas through the use of one or more drilling installations and includes any work or activity related to the program.*

***drilling rig** means the equipment used to conduct well operations and associated systems, including power systems, control systems and monitoring systems.*

***drilling riser** means the connection between a subsea blowout preventer and a mobile offshore platform.*

***drilling unit** means a fixed or mobile offshore platform, or a vessel used in any well operation, that is fitted with a drilling rig, including all systems and equipment installed on the platform or vessel that are related to well operations and marine activities.*

***drill site** means a location where a drilling rig is or is proposed to be installed.*

***environmental load** means a load imposed by meteorological or oceanographic conditions, such as winds, waves, tides, currents or snow, ice conditions, regional ice features, such as sea ice or icebergs, a seismic event or any other naturally occurring phenomenon.*

***environmental program** means a program pertaining to an environmental study as defined in subsection 119(1) (or 122(1)) of the Act.*

***exploratory well** has the same meaning as in subsection 119(1) (or 122(1)) of the Act.*

***floating platform** means a column-stabilized mobile offshore platform, a surface mobile offshore platform or a fixed floating offshore platform, including a tension leg platform or a spar platform.*

***flow allocation procedure** means the procedure*
(a) to 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) to allocate production among fields whose petroleum is combined for the purpose of storage or processing.

***flow calculation procedure** means the procedure to convert raw meter output to a measured quantity of petroleum or water.*

***flowline* means any line, other than a pipeline, that is used to transport fluids between a well and equipment used for the production of petroleum that is located at a production site or to transport fluids between a well and any systems or equipment that are used in support of that production and between those systems or equipment and the production equipment.**

***flow system* means the flow meters, auxiliary equipment attached to the flow meters, fluid sampling devices, production test equipment, 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, vented or transferred from a production installation.

***formation flow test* means an operation**
(a) to induce the flow of formation fluids to procure reservoir fluid samples and determine reservoir flow characteristics; or
(b) to inject fluids into a formation to evaluate injectivity.

***functional load* means any construction load or operating load other than an environmental load or accidental load.**

***geoscientific program* means any program that involves geological work or geophysical work, as those terms are defined in subsection 119(1) (or 122(1)) of the Act.**

***geotechnical program* means any program that involves geotechnical work, as defined in subsection 119(1) (or 122(1)) of the Act, that is undertaken to assess whether the seabed or shallow subsurface, as the case may be, is suitable to support installations or any other structures.**

***installation* means, except in Part 5, a drilling installation, production installation or accommodations installation.**

***life-saving appliances* includes lifebuoys, survival craft, launching and embarkation appliances, marine evacuation systems and visual signals.**

***load* includes a functional load, environmental load, accidental load and abnormal load.**

***LSA Code* means the annex to International Maritime Organization Resolution MSC.48(66), International Life-Saving Appliance (LSA) Code.**

***major accidental event* means an unexpected or unplanned event or circumstance or series of unexpected or unplanned events or circumstances that may lead to the loss of more than one life or uncontrolled pollution.**

***marine activities* means activities related to the stability, station-keeping and collision avoidance of floating platforms and includes mooring, dynamic positioning and ballasting.**

***mobile offshore platform* means a platform that is designed to operate in a floating or buoyant mode or that can be moved from place to place without major dismantling or modification, whether or not it has its own motive power.**

***operations site* means a site where an authorized work or activity is carried out.**

***operator* means a person that holds an operating licence issued by the Board under paragraph 138(1)(a) (or 142(1)(a)) of the Act and applies for or has been granted an authorization.**

***physical and environmental conditions* means the physical, geotechnical, seismic, oceanographic, meteorological or ice conditions that might affect an authorized work or activity.**

***pipeline* has the same meaning as in CSA Group standard Z662, Oil and gas pipeline systems, as it relates to offshore pipelines.**

***pollution* means the introduction into the environment of any substance or form of energy outside the limits applicable to an authorized work or activity.**

***pressure system* means piping, pressure vessels, safety components and pressure components, including elements attached to pressurized parts, such as flanges, nozzles, couplings, supports, lifting lugs, safety valves and gauges.**

***production installation* means the**
- ***(a)* the systems and equipment used for or in support of the production of petroleum, including those that are used for separation, treating and processing;**
- ***(b)* the systems and equipment used to conduct well operations;**
- ***(c)* any systems and equipment related to marine activities;**
- ***(d)* any associated aircraft landing areas, storage areas or tanks and accommodations areas; and**
- ***(e)* any associated platforms, artificial islands, subsea production systems and offshore loading systems.**

***production project* means a project for the purpose of developing a production site on, or producing petroleum from, a pool or field, including any work or activity related to the project.**

***production riser* means the connection between subsea production equipment and a production platform.**

***production site* means a site where a production installation is or is proposed to be installed.**

***recovery of petroleum** means the recovery of petroleum under foreseeable economic and operational conditions.*

***relief well** means a well that is drilled to assist in controlling a blowout in an existing well.*

***reportable incident** means an event that resulted in any of the following occurrences or in which an occurrence referred to in any of paragraphs (a) to (f) was narrowly avoided:*
(a) loss of life;
(b) fire or explosion;
(c) collision;
(d) pollution;
(e) leak of a hazardous substance;
(f) loss of well control;
(g) impairment of a support craft or of any of the structural elements of an installation – or any system or equipment – that is critical to safety;
(h) impairment of any of the structural elements of an installation - or any system or equipment - critical to environmental protection;
(i) implementation of emergency response procedures.

***safety-critical element** means any system or equipment, including software and temporary or portable equipment, that is critical to the safety or integrity of an installation or to preventing the installation from polluting, including*
(a) any system or equipment
(i) that is intended to prevent or limit the effects of a hazard that could cause a major accidental event, or
(ii) whose failure could
(A) cause a hazard that could cause a major accidental event, or
(B) worsen the effects on the installation of a major accidental event; and
(b) any software or temporary or portable equipment that affects any system or equipment referred to in paragraph (a).

***subsea production system** means equipment and structures that are located on or below the seabed for the production of petroleum from, or for the injection of fluids into, a field under a production site and includes production risers, flowlines and associated control systems that are located upstream of the isolation valve.*

***support craft** means a vessel, vehicle, aircraft or other craft used to provide transportation or assistance to persons at an operations site.*

***waste material** means any garbage, refuse, sewage or waste fluids or any other useless material that is generated during the carrying out of any work or activity, including used or surplus drill cuttings and drilling fluid as well as produced water.*

***watertight** means designed and constructed to withstand a static head of water without any leakage.*

***well control** means the control of the movement of fluids into or from a well.*

***well operation** means an operation related to the drilling, completion, recompletion, re-entry, intervention, workover, suspension or abandonment of a well.*

***workover** means an operation on a completed well that requires removal of the tree or the tubing.*

***zone** means any stratum or any sequence of strata, including a zone that has been designated as such by the Board under paragraph 60(a).*

Refer also to definitions under the *Accord Acts* and as set out above in this section of the Guideline. When applying the *Accord Acts* and the associated regulations, particular attention must be paid to terms defined therein and their use throughout such legislation.

Section 2 – Incorporation by Reference

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2 (1) In these Regulations, any incorporation by reference of a document is an incorporation of that document as amended from time to time.

Bilingual documents

(2) Despite subsection (1), if a document that is incorporated by reference is available in both official languages, any amendment to it is incorporated only when the amended version is available in both official languages.

Most recent version of documents

Recognizing that documents incorporated by reference in the *Framework Regulations* can be amended from time to time, operators are responsible for ensuring that the most recent version of the document is used. Operators need to assess the changes that were made and determine whether they are still in conformance with the incorporated sections of the referenced document. Processes should be established to review and implement any changes.

Documents incorporated by reference

When a document is referenced directly in the regulations, this is known as incorporation by reference and the operator must comply with the incorporated document as they would any other legislative requirement. The operator may use other documents (e.g., codes, standards) in combination with other measures as long as they meet or exceed the requirements of the incorporated document, paying particular attention to any mandatory requirements. A summary of all documents that have been incorporated by reference in the *Framework Regulations* is provided in the Bibliography.

Documents referenced in applications

When a document is referenced directly in an application for an OA or approval as the means by which an operator will meet a regulatory requirement (e.g., states that Well Control Equipment will meet the requirements of API Standard 53, as an example), this is known as an adopted document. While the adopted document may not have been incorporated by reference in the regulations, it is a commitment that an operator has made within an application to the *Regulator.* As such, the operator must comply with the requirements of that adopted document as they would any other legislative requirement.

Normative vs. informative information

When a document is incorporated by reference or is adopted as part of an application for an OA or approval, there should be an understanding of the differences between normative (i.e., mandatory - shall, must) and informative (i.e., non-mandatory references - should, may). Unless otherwise stated in the regulation, normative information must be interpreted to be a mandatory requirement and informative information should be treated as advice or recommendations. Examples of "normative vs. informative information" are provided in section 2 of the *Guideline for the Occupational Health and Safety Regulations*.

Other documents referenced in this guideline

When a document is referenced only in this Guideline and it is not incorporated by reference in the *Framework Regulations*, it is being identified as a source of related good practice information for consideration. In these cases, the *Regulator* has included guidance notes with respect to application of the document. Unless otherwise specified, all information within the document, whether it is normative or informative, should be considered. A summary of all documents that have been referenced in the *Framework Guideline* is provided in the Bibliography. The revision date at the time of issuance of this Guideline is included in the Bibliography. Updated documents will be reviewed once amended and the date updated. Updates to referenced documents may result in an amendment to the section of the Guideline in which it is referenced.

PART 2: EXPERIENCE, TRAINING, QUALIFICATIONS AND COMPETENCE

Section 3 – Requirements

3 (1) An operator must ensure that any person to whom a duty is assigned or who carries out a work or activity under these Regulations has the necessary experience, training, qualifications and competence to carry out that duty, work or activity safely, in a manner that protects the environment and in compliance with these Regulations.

Sufficient number and supervision

(2) The operator must ensure that the persons referred to in subsection (1) are sufficient in number and receive the necessary supervision to ensure safety and the protection of the environment.

All Works or Activities

With respect to section 3 and paragraph 4(1)(h) of the *Framework Regulations* and to Part 4 of the *OHS Regulations*, a competency assurance program should be in place that takes into consideration the following:

- specific and general requirements for the experience, training, qualifications and competency of persons*;*
- any requirement specified in a code or standard that has been incorporated by reference in either the *OHS Regulations* or the *Framework Regulations;*
- any requirement that has been adopted as part of a code or standard referenced in the application for an OA; and
- any assumptions or measures identified during risk assessments pertaining to training or competency.

For all works or activities, the competency assurance program should make reference to the COP TQOP. While the COP TQOP does contain a number of specific and general requirements, it does not include all roles or other requirements that need to be addressed as part of a competency assurance program. The operator is responsible to ensure that experience, training and competency requirements are met for all roles as required by subsection 3(1) of the *Framework Regulat*ions.

Drilling and Production Installations

The competency assurance program for drilling and production on installations should also include a description of processes for:

- Selection of persons, including objective criteria for requisite experience, training, qualifications or other criteria (e.g., medical, attributes).
- Ensuring persons obtain and maintain the necessary certification (e.g., professional, marine, trade), training and qualifications commensurate with the tasks they are expected to perform. Dependent on the nature of the work or activity, the competent person should maintain professional status or designation with a third party (e.g., professional engineers, safety professionals).
- Ensuring persons are knowledgeable and competent and that they maintain their competency in the following:
  - the hazards, risks and equipment specific to the installation;
  - operating and maintenance processes;
  - abnormal and emergency response processes, including simulator training, exercises and drills, when appropriate; and
  - safety or environmental critical tasks (as determined by risk assessments).
- Ensuring that members of the leadership team are provided with the appropriate skills, training and competency to enable them to foster an appropriate culture within the organization.
- Ensuring that retraining or competency assessments are performed periodically or when there are changes to regulations, standards, equipment, processes, etc.
- Monitoring and auditing training and competency, including internal audits and external audits of contractors, service providers and training providers.
- Guidance is also provided in the following references:
  - *ISO 10015 Quality Management – Guidelines for competence management and people development.*
  - *ISO 10018 Quality Management – Guidance for people engagement.*
  - *IOGP Report 454 Human factors engineering in projects.*
  - *Energy Institute Guidance on Human Factors safety critical task analysis.*
  - In addition to information in the COP TQOP:
    - With respect to persons involved in well operations, consideration should also be given to guidance provided in *ISO/TS 17969 Petroleum, petrochemical and natural gas industries - Guidelines on competency management for well operations personnel* and on guidance found on IADC's website.
    - With respect to other personnel, consideration should also be given to guidance on OPITO's website.

Organizational Competence

With respect to subsection 3(2) of the *Framework Regulations*:

- Formal processes should be in place to ensure that the organization, inclusive of contractors, subcontractors and persons working onshore and offshore, has sufficient trained and competent individuals to complete all authorized activities (e.g., production, drilling, construction, diving, well completions, geophysical activities) safely, without polluting the environment.

- The number of individuals required should be determined based on formal task and human factor assessments (e.g., fatigue, breaks, overload), as appropriate, with results documented. It should also include sufficient supervision to ensure that work is completed in accordance with the management system.
- The organization should also have resilience and redundancy in critical roles for normal and emergency operations in the event of unforeseen circumstances (e.g., illness, injury, compassionate leave, succession planning).

Organizational Structure

To assist with compliance to subsection 3(2) of the *Framework Regulations* and pursuant to subsections 5(1) and paragraphs 9(2)(d), 10(2)(h) and 11(2)(d) of the *Framework Regulations*, there must be an organizational structure in place for normal operations and for emergency operations. Organizational charts should be in place that show the following:

- The reporting structure for all onshore and offshore roles, including anyone who is normally at the workplace, inclusive of contractors, subcontractors, etc.
- The number of positions in each role and how many are working days/nights.
- The reporting structure between the workplace and the providers of service, including those that may be mainly located onshore (e.g., medical services, weather forecasting).

The organizational structure should reflect all roles for all types of work or activities that are planned to be conducted concurrently with normal or steady-state operations, including any additional construction, installation, commissioning or decommissioning activities, etc.

PART 3: MANAGEMENT SYSTEM (Section 4 – 7)

Requirements

4 (1) An operator must, for the purposes of reducing safety and environmental risks, preventing pollution and ensuring the conservation of petroleum resources, develop a management system that meets the following requirements:
(a) it must be set out in writing;
(b) it must apply to all of the works and activities referred to in the operator's application for authorization;
(c) it must correspond to the scope, nature and complexity of the works and activities and the associated hazards and risks;
(d) it must be explicit, comprehensive and proactive;
(e) it must foster a culture of safety;
(f) it must establish conditions under which a person who makes a report that relates to safety or protection of the environment will be protected from reprisal;

(g) it must include processes for integrating works and activities and technical systems with the management of human and financial resources;

(h) it must include processes to ensure that all persons have the necessary experience, training, qualifications and competence and receive the necessary supervision to carry out the duties they are assigned;

(i) it must set out the roles, responsibilities and authorities of all persons exercising functions under it, as well as the processes for making those persons aware of their roles, responsibilities and authorities;

(j) it must include processes for coordinating the carrying out and management of the works and activities among the operator, employers, suppliers, service providers and other persons that are subject to it;

(k) it must include processes for the internal and external communication of documents and information relating to safety or the protection of the environment;

(l) it must include a process for the efficient and immediate transmission, at every shift handover, of documents and information relating to any conditions, mechanical or procedural deficiencies or other problems that may have an impact on safety or the protection of the environment;

(m) it must include processes

> ***(i) for identifying hazards that may arise during routine and non-routine operations,***
>
> ***(ii) for assessing the risks associated with those hazards and for reducing those risks through the implementation of control measures, and***
>
> ***(iii) for establishing an inventory of those hazards and control measures and for maintaining that inventory;***

(n) it must include processes for investigation and reporting, for the purposes of section 179, the root causes of any reportable incident, the contributing factors and the measures to be implemented to prevent recurrence of the incident;

(o) it must include a process for establishing a system to analyze trends in hazards and reportable incidents;

(p) it must include processes for identifying, evaluating and managing all systems and equipment that are critical to safety or to the protection of the environment;

(q) it must include processes for identifying, evaluating and managing any changes that could affect safety, the protection of the environment and the conservation of petroleum resources;

(r) it must include processes for identifying tasks that are critical to safety, the protection of the environment and the conservation of petroleum resources;

(s) it must include processes for establishing and maintaining measurable goals and performance indicators that are applicable to it;

(t) it must include processes for periodic internal audit and review to identify areas for improvement and the preventive and corrective measures to be taken if deficiencies are identified;

(u) it must include processes for monitoring compliance and preventing non-compliance with the requirements of these Regulations, the provisions of Part III of the Act and any requirements that are determined by the Board under that Part;

(v) it must include processes for inspection, monitoring, testing and maintenance to ensure the continued integrity of all installations, including their systems and equipment, pipelines and vessels, and for the taking of corrective measures if deficiencies are identified;
(w) it must include the policies and indicate the standards on which it is based;
(x) it must include a process to ensure that all documents associated with it are approved by a person with the necessary authority, periodically reviewed and updated when necessary;
(y) it must include a process for establishing a system to manage any records associated with it, and the records necessary to support operational and regulatory requirements, for the purpose of ensuring that those records are generated, identified, controlled and retained and are readily accessible for consultation and examination; and
(z) it must include processes for controlling and coordinating work, including with respect to the issuance of work permits required under Part 10 and the identification of the works and activities for which a work permit is required.

Documentation

(2) The operator must ensure that the processes and policies included in the management system and the standards referred to in it are readily accessible for consultation and examination.

Organization

(3) The documentation associated with the management system must be organized and set out in a logical fashion to allow for ease of understanding and efficient implementation.

Processes and procedures

(4) In this section, a reference to a process includes any procedures that are necessary to implement the process.

Human resources

5 (1) An operator must put in place an organizational structure that includes sufficient human resources to implement and continually improve the management system.

Accountable person

(2) The operator must designate an employee as the accountable person for the management system and must ensure that the accountable person has the necessary authority over the human and financial resources that are required to implement and continually improve the system.

Name, position and contact information

(3) The operator must ensure that the name, position and contact information of the accountable person is submitted to the Board at the time the application for an authorization is made, when a new designation is made under subsection (2) and any time a change is made to the name, position or contact information of the accountable person.

Implementation

6 (1) An operator must ensure that the management system is implemented before the commencement of any authorized work or activity.

Compliance

(2) The operator must ensure that all employees, employers, suppliers, service providers and other persons that are subject to the management system comply with the requirements of the management system.

Continual improvement

7 The accountable person referred to in subsection 5(2) must ensure that the management system is continually improved.

General

- Refer to the requirements for occupational health and safety management systems and for occupational health and safety programs under the *Accord Acts*[7] and Part 2 of the *OHS Regulations*.
- The management system should be maintained, updated and continually improved upon.

Management System Elements

Guidance on each element of a management system is provided as follows:

a. Management System Standards

With respect to paragraph 4(1)(w) of the *Framework Regulations*, the management system must include the policies and indicate the standards on which it is based. The following documentation provides information which should be consulted for the development of an integrated management system:

- The suite of ISO Management System Standards, in general, can be applied broadly to any activity. This includes the following:
  - *ISO 9001 Quality management systems – requirements*

[7] C-NLAAIA 205.015, 205.02; CNSOPRAIA 210.015, 210.02

  - *ISO 14001 Environmental management systems – requirements*
  - *ISO 29001 Petroleum, petrochemical and natural gas industries – Sector-specific quality management systems – Requirements for product and supply organizations*
  - *ISO 31000 Risk management – Guidelines*
  - *ISO 45001 Occupational health and safety management systems – requirements*
- *IOGP Report 510 Operating Management System Framework*, *IOGP Report 511 OMS in practice report – supplement to Report No. 510*, *Operating Management System Framework* and *IOGP Report 423 HSE management – guidelines for working together in a contract environment*.
- ISM Code. However, it should be noted that this code only applies to marine systems on safety convention vessels. Installations and vessels that are safety convention vessels should have valid and current certification with respect to this code.
- *IADC HSE Case* should be considered for drilling installations.
- *API RP 75 Safety and Environmental Management System for Offshore Operations and Assets.*

The operator should also identify if other standards are being applied by the installation or vessel owner, contractors, third party contractors, supplier and providers of services. If third party certification is being maintained this should also be specified (e.g., ISO, ISM).

b. Scope

With respect to paragraphs 4(1)(b) and (c) of the *Framework Regulations*, the management system must cover all works or activities and as such, should cover all activities conducted onboard or near the installation, vessel or aircraft, activities that occur onshore in support of the program and other support activities (e.g., transport of persons and cargo, medical services, environmental monitoring). If other management systems are being used by contractors, suppliers or providers of service, they should also be described. The scope should reflect geographic boundaries (spatial scope), duration (temporal scope) or limitation to particular activities (e.g., diving projects). It should also reflect all work and activities that fall within the scope of the application for an OA conducted in relation to pre-mobilization, mobilization, exploration, drilling, installation, construction, commissioning, diving, installation, operations, maintenance, life extension, decommissioning and abandonment, and post-abandonment, as applicable.

c. Legal Requirements

With respect to paragraph 4(1)(u) of the *Framework Regulations*, the management system should be based on and reflective of the following, as applicable:

- The *Accord Acts* and regulations, including references to the acts or regulations of other authorities (e.g., Social Legislation, IAA).
- Requirements of the *Regulator*, such as:
  - Commitments or conditions of *Development Plans* for activities associated with production projects.

  - Commitments or conditions of associated Environmental Assessments and Impact Assessments.
  - Benefit Plans.
  - Commitments or conditions of RQs.
  - Adopted COPs (required by the CSO).
  - Commitments or conditions of authorizations and associated approvals.
- Requirements of other authorities and any associated exemptions that have been granted.
- Requirements of flag state and classification society requirements, including those in relation to the maintenance of additional class notations.

d. Policy and Objectives

With respect to paragraph 4(1)(w) of the *Framework Regulations*, the management system must include the policies on which it is based, including any associated quality policy, environmental protection policy or occupational health and safety policy under Part III.1 of the *Accord Acts* and section 4 of the *OHS Regulations*. Policies may be combined as long as they meet the objectives of all requirements and adopted standards. Policies should be signed by an accountable senior person, prominently posted at the workplace and broadly applicable to all workplace parties, including providers of service.

e. Leadership Commitment and Culture

With respect to paragraphs 4(1)(e) and (f) of the *Framework Regulations*, leadership should be committed to developing, leading and promoting a culture in the organization that supports the intended outcomes of the management system, including safety and protection of the environment. The management system should also cover the processes for right to know, right to participate and right to refuse as described in the guidance for sections 5 and 6 of the *OHS Regulations*.

Guidance on the cultural threats that should be mitigated and the associated defenses that should be put in place are provided in the CER, C-NLOPB and CNSOPB "*Statement on Safety Culture*", which is available on the *Regulator*s' respective websites.[8] It should be noted that while the term "Safety Culture" is used, the term safety encompasses the safety of persons and others who may be affected (e.g., simultaneous operations, general public), operational/process safety, environmental protection, asset integrity and security.

Some other documents to consider in establishing an appropriate safety culture include:

- *IOGP Report 452 Shaping safety culture through safety leadership*
- *IOGP Report 453 Safety Leadership in Practice: A guide for managers*
- *Center for Offshore Safety Publication COS-3-04 Guidelines for Robust Safety Culture*

[8] C-NLOPB – www.cnlopb.ca; CNSOPB – www.cnsopb.ns.ca

f. Management of Contractors, Providers of Service and Suppliers

With respect to paragraphs 4(1)(b), (c), (g) and (j) of the *Framework Regulations*, the following processes should be established and implemented:

- Process for selection, integration and monitoring of contractors, providers of service and suppliers. The process should also describe the processes the operator has in place for reviewing the operating history and evaluating relevant quality, health, safety and environmental performance (e.g., incidents, audits, inspections, hazard reports, maintenance, training) of contractors, providers of service and suppliers.
- Process for ensuring that materials or equipment purchased will be in compliance with relevant requirements and commitments.

Any changes should be managed through the management of change process.

g. Communication

With respect to paragraphs 4(1)(j), (k), (l) and (z) of the *Framework Regulations*, formal procedures should be in place for internal and external communication of information. They should include the following:

- The format and structure of HSE meetings.
- The format and structure of shift and tour handovers.
- The format and structure of toolbox talks and job safety analysis.
- Communication of new hazards.
- Communication of incidents.
- Communication of changes.
- Communication of information to external stakeholders, including the public.

Any differences in language or other obstacles to effective communication should also be addressed pursuant to paragraph 41(c) of the *Framework Regulations*.

With respect to paragraphs 4(1)(l) of the *Framework Regulations*, shift and tour handovers should:

- cover all departments or groups onboard;
- ensure coordination and communication between the supervisors of each department or group; and
- ensure coordination and communication between the person in charge of the operations site and the operator’s representative if they are not the designated person in charge.

The processes should be effective, documented and monitored, and records should be maintained.

h. Control of Documents

With respect to paragraphs 4(1)(r) and (x) and subsection 4(2) of the *Framework Regulations*, these are interpreted to apply to all documents that form part of the management system, including policies, plans, procedures, practices, operations and maintenance manuals, work instructions, checklists, diagrams, layout drawings, piping and instrumentation drawings, electrical and instrumentation schematics, manufacturer information, safety data sheets, etc. The operator should have mechanisms in place to ensure that management system documents are controlled, including the procedures and practices of contractors, providers of service or suppliers when they have been adopted for the program. Expectations on control of documentation are as follows:

- Processes should describe how documents are developed, reviewed, approved and risk ranked (if applicable) by appropriate persons. These processes should ensure that documents are sufficiently detailed, readily available, logical, accurate, easily understood and maintained up-to-date.
- Processes should describe how controlled information is managed and describe the management and removal of uncontrolled information. Processes should ensure that superseded version(s) of information are removed or that alternative measures are put in place to ensure they are not inadvertently used.
- Processes should describe how the operator manages documents that are considered controlled documents by the *Regulator* or other authorities, including the CA are maintained. Regulatory required documents, such as those that form part of the application for an OA or COF, should not be changed or implemented until they have been accepted.
- Processes should be in place to make documents readily available to all persons required to use them at the point of use and to provide instruction and training, as necessary.
- Processes should be in place for providing feedback on documents and for updating the documents based on user input, lessons learned, incidents, etc.
- Processes should be in place for auditing and observing compliance to documents, based on risk.
- Processes should be in place for the periodic review and update of documentation. Any procedures that are regulatory or critical to safety or the environment should be reviewed more often, whereas other documents that are not as critical may be reviewed less often.
- Any changes to documentation, especially documents that are critical to safety or the environment, should be made through the management of change system and reviewed and approved by appropriate persons before a change is made, with due consideration to any regulatory requirements or risk assessments.
- Processes should be in place for providing updates to procedures, which depending on risk, may also include providing awareness, instruction or additional training to all persons that may be affected.

i. Control of Records

With respect to paragraph 4(1)(y) of the *Framework Regulations*, refer to requirements for specific records to be maintained as prescribed in the *Accord Acts*, the *Framework Regulations* and the *OHS Regulations*. This must include any records that are required to be maintained as part of the management system and should also include any records that are required under any codes or standards that have been adopted. Records which are required to be maintained to demonstrate compliance to regulatory requirements should be complete and accurate. Any false entry or statement in a record, or the destruction or modification of any report, record or other document required to be retained, submitted or produced upon request is considered an offense under the *Accord Acts*[9].

j. Management of Change

With respect to paragraph 4(1)(q) of the *Framework Regulations*, formal processes for identifying, evaluating and managing changes should include the following:

- management system;
- scope of work or activities;
- regulatory requirements or standards;
- hazards and risks;
- equipment;
- software;
- materials;
- processes (including changes in the status of a well to a higher risk well);
- documented information (e.g., procedures, work instructions, checklists, drawings, plans);
- organizational structure;
- roles or responsibilities;
- persons (including employers, employees, providers of service, etc.); and
- temporary changes (including equipment, processes or personnel).

Procedures should be in place that include the following:

- roles and responsibilities for initiating and authorizing changes;
- processes for the identification of hazards, conduct of associated risk assessments and implementation of any measures as necessary with the change;
- processes for identifying all impacts associated with the change, including safety reviews, as necessary;
- consultation and effective communication with those affected by the change, if feasible, before the change is made, including any training or awareness;

[9] C-NLAAIA 194(1)(b)(c), 205.104(1)(b)(c); CNSOPRAIA 199(1)(b)(c), 210.106(1)(b)(c)

- processes for ensuring that those responsible accept and take ownership of the implementation of the change; and
- processes for following up on the effectiveness of each change.

Any change, including a change made by a contractor, supplier or provider of service can have unintended impacts if it is not managed appropriately. The process for management of change should be applied to changes made by a contractor, supplier or provider of service as if those changes were made by the operator.

k. Hazard Identification and Risk Assessment

With respect to paragraphs 4(1)(m) and (o) of the *Framework Regulations*, an operator is required to establish a robust process for managing the risks associated with the work or activity. Refer also to the applicable specific requirements for risk assessments under sections 24 (for production projects), 107 and 108 (for installations) of the *Framework Regulations* and Part 2 of the *OHS Regulations*. Refer also to specific requirements for conducting risk assessments for certain equipment or activities under both the *Framework Regulations* and the *OHS Regulations*.

With respect to section 41 of the *Framework Regulations*, the operator must take all measures necessary to ensure safety and the protection of the environment during any authorized work or activity. The operator should also refer to the *Accord Acts* and the associated regulations for requirements with respect to assessing the risk, taking care to implement measures that reduce the risk if the risk cannot be eliminated. These requirements are intended to protect health, safety and the environment and to ensure the responsible management of petroleum resources. In line with these requirements, authorized work and activities are expected to be carried out in a manner that meets the following regulatory goals within the operator's management system:

- The work or activity should be controlled in a manner that achieves safety (i.e., safety of operations, prevention of accidents and prevents injuries and illnesses to persons), protection of the environment (i.e., pollution prevention), and management of petroleum resources (i.e., prevention of waste).
- All foreseeable hazards should be identified and if that hazard is unable to be eliminated, the risk is evaluated. Measures should be implemented to avoid, prevent, reduce and mitigate those associated risks (e.g., ALARP).
- Preventive measures should be aimed at elimination of identified hazards, reduction of the risks posed by those hazards and finally, taking of protective measures and preparation for response measures to minimize consequences of hazard exposure including design, substitution, engineering controls, administrative controls, protective equipment, etc.
- Processes for the ongoing identification, reduction and management of risks to safety, the environment and resource conservation should be implemented. The management

system should also correspond to the scope, nature and complexity of the proposed work or activity and to the hazards and risks associated with the work or activity.

Consistent with the requirement to “take all measures necessary to ensure safety and the protection of the environment,” an operator should undertake systematic and comprehensive hazard identification and risk assessment and it should adopt industry best practices and other measures, as required, to reduce the risk to ALARP throughout the life cycle of the work or activity. The ALARP approach also recognizes that the resources (e.g., cost and time) required to further reduce a risk should be proportional to the reduction in risk that will be achieved. Maintaining risks to ALARP will require continual assessment of emergent changes to technology, operations or conditions to ensure that the operator’s risk reduction measures continue to reduce risks to ALARP.

The onus is on an operator to approach management of any risk in a fashion that can be demonstrated to comply with any explicit regulatory requirements at minimum, and to achieve a condition in which identified risks are ALARP. In summary, it is the expectation that the associated facilities and equipment will be designed, operated and maintained to comply with any explicit regulatory requirements at minimum, to achieve a level of safety and protection to persons and the environment that is ALARP, and to see that the operator’s management system will ensure this remains ALARP. The management system should ensure that appropriate measures are undertaken to identify all foreseeable hazards, and to prevent, reduce and manage associated risks to the health and safety of persons, protection of the environment and conservation of the resource over the life cycle of the work and activity.

In general, the processes in place should address the initial and ongoing identification of hazards that can result in either a major accidental event or an accidental event. The management system should include the following:

- Project wide hazards (e.g., helicopter operations, support craft operations, local physical and environmental conditions).
- Activity specific hazards (e.g., production, drilling, completions, formation flow testing, geoscientific, diving, installation, decommissioning).
- Situation and task specific hazards (e.g., breaking containment, work at height).
- Abnormal modes of operation or simultaneous operation hazards (e.g., upsets, emergencies, ongoing construction, installation or commissioning concurrently as other operations).

Guidance for hazard identification and risk assessment is provided in *ISO 31000 Risk management - Guidelines*.

Some additional notes:

- Risk assessments should include any hazards, assumptions or measures identified from the environmental assessment processes completed under the *Accord Acts*, CEAA or the

IAA, as the case may be, and should incorporate any related conditions issued by the *Regulator* or the Minister of ECCC.

- Risk assessments should be conducted in consultation with persons at all levels of the organization with expertise and knowledge, and with all persons who may be involved in the project, activity or situation to which hazards may pose a risk, including contractors, providers of service and suppliers.
- Members of the leadership team should also have the same understanding of the hazards, risks and associated measures that need to be in place.
- Hazards, risks and associated measures must be communicated to all persons who are directly affected pursuant to paragraph 4(1)(l) and subparagraphs 9(2)(b)(vii) and 10(2)(b)(vii) of the *Framework Regulations.*
- Hazards, risks and associated measures should be reassessed routinely through the life of the proposed work or activity.
- Hazards, risks and associated measures must be clearly identified in the Safety Plan and Environmental Protection Plan as required by sections 9 and 10 of the *Framework Regulations*, respectively, and should also be reflected in associated management system documentation. Measures should be identified in any description of equipment, procedures and training and competency programs.

l. Asset Integrity

The management system should describe the processes for ensuring the asset integrity of all equipment, including any equipment provided by a contractor, supplier or provider of service. With respect to paragraphs 4(1)(p) and (v) of the *Framework Regulations*, refer to general requirements for asset integrity under paragraph 41(e) of the *Framework Regulations* and for equipment, machines and devices covered in the *OHS Regulations*, refer to the requirements and associated guidance in Part 18 of the *OHS Regulations*. For prescribed installations, refer to the requirements under sections 98, 110, 153, 154, 155, 158, 159, 160 and 161 of the *Framework Regulations* and the associated guidance and any prescribed requirements throughout the *Framework Regulations* with respect to inspection, testing and maintenance. As part of the DOF provided pursuant to the *Accord Acts*[10], the operator must declare that the equipment and installations to be used in the work or activity are fit for the purposes for which they are to be used, including temporary or third party equipment. The operator should have sufficient competence and resources to make its own independent declaration. While operators can rely on certification issued by third party organizations, this does not relieve the operator of overall accountability for equipment and as such the operator should be able to demonstrate how this accountability is not lost.

m. Procedures and Practices

With respect to paragraph 4(1)(r) and subsections 4(2) and (3) of the *Framework Regulations*, refer also to guidance on operational control and specific or general requirements for

[10] C-NLAAIA 139.1; CNSOPRAIA 143.1

operations and maintenance procedures that is provided in “a” above and guidance for control of documents under “h” above. Requirements related to procedures and practices are also found throughout the *Framework Regulations* and *OHS Regulations*. Specific requirements for operating and maintenance procedures for drilling, production or accommodations installations are also found in sections 73, 156 and 157 of the *Framework Regulations.* If a contractor, provider of service or supplier is using their own documentation as part of the work or activity that has been authorized, then as part of the DOF pursuant to the *Accord Acts*[11], the operator must declare that all procedures and practices to be used in relation to safety and protection of the environment are appropriate and that processes are in place to ensure that they continue to be appropriate. The operator should have sufficient competence and resources to make its own independent declaration. The operator should include a list of all safety or environmentally related procedures and practices in the Safety Plan or Environmental Protection Plan, as applicable, that have been developed by other workplace parties and have been accepted for use by the operator as part of its DOF. Procedures or practices that are being introduced or changed should not be used until they have been reviewed and accepted by the operator. Expectations on procedures and practices are as follows:

- Procedures and practices should be in place for all normal operational and maintenance activity, emergency operations and non-standard modes (e.g., temporary, infrequent) of operation.
- Processes should describe how documentation is maintained such that it is in compliance with the regulations and any adopted standards. The requirements should be clearly stated within the document for change management purposes.
- Processes should describe how tasks critical to safety or protection of the environment are identified. Any critical measures should be clearly identified within the document and linked to associated risk assessment processes for change management purposes.
- Prior to the start of a new operation, changed operation or completion of a non-standard or high risk operation, a toolbox meeting should be held with all parties to review the operating and maintenance procedures, Contingency Plans and emergency response procedures.
- The use of procedures and practices should be monitored and audited regularly by supervisors and auditors.
- Refer to section “h” above for additional information.

n. **Work Permits**

With respect to paragraphs 4(1)(z) of the *Framework Regulations*, refer to the requirements and associated guidance for work permits under Part 10 of the *OHS Regulations*, including the types of activities that should be conducted under a work permit. While the *OHS Regulations* focus on OHS, the same guidance should be considered for the purposes of preventing pollution and ensuring the ongoing integrity of the installation. For production,

[11] C-NLAAIA 139.1; CNSOPRAIA 143.1

drilling or accommodations installations, refer to the guidance provided for work permits under sections 101 and 102 of the *Framework Regulations*.

o. Organizational Structure and Roles, Responsibilities and Authorities

With respect to paragraph 4(1)(i) and section 5 of the *Framework Regulations*, the operator is responsible to ensure that the management system describes the roles, responsibilities and authorities of all persons employed in the performance of the authorized work or activity and, more particularly, should reflect the roles, responsibilities and authorities as outlined in the *Accord Acts*, the *Framework Regulations*, *OHS Regulations* and requirements of other applicable authorities. The roles, responsibilities and authorities of all functional groups (e.g., health, safety and environmental group, asset integrity group, emergency response teams, workplace committee, employers, supervisors, employees, providers of services and suppliers) should also be clearly described, documented and controlled so that the potential for uncertainty about responsibilities and the potential for overlap of responsibilities is minimized. In addition, the roles, responsibilities and authorities of associated regulatory agencies and the CA should be described and communicated to all persons involved in the work or activity.

p. Training and Competency Assurance

With respect to paragraph 4(1)(h) and section 3 of the *Framework Regulations*, refer also to specific and general requirements for the training, qualifications and competency of persons in the *OHS Regulations* and the *Framework Regulations* and any requirements specified in a code or standard that has been incorporated by reference in the regulations or which has been adopted for the program. As part of the DOF provided pursuant to the *Accord Acts*[12], the operator must declare that the persons who are employed are qualified and competent, including contractors, subcontractors, suppliers and providers of service. The operator should have sufficient competence and resources to make its own independent declaration. Additional details respecting the training and competency assurance processes are provided in section 3 of the *Framework Regulations*.

q. Compliance Monitoring, Performance Measurement and Continual Improvement

With respect to the *Accord Acts*[13] and paragraphs 4(1)(n), (o), (s), (t), (u) and (x) and section 7 of the *Framework Regulations*, the programs in place should include the following:

- **Management of Non-Compliances**

  For each non-compliance identified, whether it is identified as part of its internal processes or by an external party, the *Accord Acts* and regulations require that the

[12] C-NLAAIA 139.1; CNSOPRAIA 143.1
[13] C-NLAAIA 205.013(b)(d)(l)(m)(n)(q)(r), 205.015(1)(b)(c), 205.015(2)(a)(g), 205.013(3); CNSOPRAIA 210.013(b)(d)(l)(m)(n)(q)(r), 210.015(1)(b)(c), 210.015(2)(a)(g), 205.013(3)

operator take corrective and preventive measures to prevent reoccurrence of a non-compliance. When a non-compliance is identified, the operator should undertake a root cause analysis to identify improvements to the management system.

- **Performance Indicators**

  - The operator should develop a list of measurable goals and associated performance indicators to be achieved within each element of its management system and that of its contractors, suppliers and providers of service.
  - The following information can be monitored, trended and analyzed as performance indicators:
    - Outcomes from audits and inspections.
    - Outcomes from hazard identification reports – refer to “k” above for guidance.
    - Outcomes from incident investigation reports paying attention to both actual and potential severity.
    - Reliability and availability of equipment onboard an installation – refer to requirements and associated guidance in section 159 of the *Framework Regulations*.
    - Impairments to critical equipment and the mean time to repair onboard an installation – refer to requirements and associated guidance in section 159 of the *Framework Regulations*.
    - Operational and process safety indicators as described in in *API RP 754 – Process Safety Performance Indicators for Refining and Petrochemical Industries* and *IOGP Report 456 Process Safety - Recommended Practice on Key Performance Indicators*, however, compliance to these documents alone does not ensure that all appropriate performance measures for operational safety, OHS or protection of the environment will be monitored.
    - Discharges.

- **Compliance Monitoring**

  Responsibilities for the continuous monitoring of compliance with procedures and standards should be established for leadership and supervisors in accordance with the provisions of the *Accord Acts* and regulations referenced above.

- **Audits and Inspections**

  Guidance for the conduct of internal and external audits is provided by the ISO standards noted above and if performed correctly, can drive compliance and significant improvement to management systems. The following should be considered in audits and inspections:

- To the extent practicable, they should be performed by persons not directly involved in the particular area or operation, but who are knowledgeable in the particular area or operation.
- To the extent practicable, audits should be performed by persons who have formal training in the auditing of management systems.
- Audits and inspections should involve representatives from the workplace committee.
- Audits and inspections should verify compliance to the management system, the legislation and to any commitments made by the operator and conditions of approval of other requirements of the *Regulator* or other authorities, including authorizations, approvals, *Development Plans*, Environmental Assessments, Impact Assessments, etc.
- Any non-compliances or non-conformances identified should be based on factual information obtained from the review of reports, observations and interviews. If audits are too subjective or high level, they may fail to identify non-compliances and non-conformances within the system.
- They should aim to ensure that aspects of the management system, operations sites, procedures and competency programs, including those of contractors, providers of service and suppliers, are audited at least on an annual basis, with focus placed on critical procedures, equipment and competency and the measures associated with low-frequency, high severity events.
- Schedules should be developed on an annual basis with appropriate resources assigned.
- Procedures should identify how corrective and preventive actions are dealt with and communicated to leadership, tracked and closed out. There should be clear understanding of the risks to safety, environment, reputation and regulatory compliance.
- While the processes should consider the tracking, closeout and analysis of any non-compliances, non-conformances, etc., that have been identified by regulatory authorities (e.g., the *Regulator*, Transport Canada Marine Safety) or the CA, the process itself should not identify these audits as part of the management system and demonstration of due diligence.

- **Incident Investigations**

  The processes for the investigation of incidents should:

  - Establish the roles and responsibilities of persons involved in the incident investigation process and the subsequent review of incident investigation reports, including those of employer and employee representatives of the workplace committee.
  - Specify qualifications, training and competency requirements for persons involved in incident investigations and the subsequent review of incident investigation reports.
  - Specify the composition and requirements for investigation teams.
  - Provide clear criteria for the internal and external communication of incidents and investigation results.

- Specify requirements for conducting incident investigations and outline expected outcomes, such as the identification of root cause(s), corrective and preventive actions.
- Specify how incidents and subsequent corrective and preventive actions are tracked and communicated to all relevant persons (e.g., onshore management, contractors, authorities, CA).
- Specify performance monitoring criteria for incidents, such as measures for ensuring corrective and preventive actions are implemented in a timely manner.
- Specify a mechanism for assessing the effectiveness of any corrective and preventive actions taken.
- Specify how results from incident investigations are used for the continual improvement of management systems.
- Describe the monitoring, auditing and review of the effectiveness of the incident investigation process.

Refer also to the requirements and associated guidance in section 179 of the *Framework Regulations*.

- **Lessons Learned**

  - The operator should have a lessons learned program that captures learnings from incidents, near misses, work and maintenance activities, special projects, etc., and that can be applied to enhance the processes of operator, contractors, subcontractors, suppliers or providers of service.
  - There should be arrangements in place for issuing HSE alerts and bulletins and for responding to other HSE alerts and bulletins issued in the *Offshore Area* or in other areas of the world that are relevant. For sharing alerts related to their work in the *Offshore Area,* CAPP has established a Safety Share portal for its members.
  - In addition to monitoring any alerts by their interest owners or their own companies, operators should be monitoring any alerts or bulletins that have been issued by contractors, subcontractors, suppliers or providers of service.

- **Management Review**

  The operator should have processes established for discussing and reviewing any noted items of non-compliance, items of non-conformance, potential future issues, stakeholder feedback, internal/third party audit results or items of continual improvement opportunity with leadership to ensure that adequate planning and resources are provided.

A summary of all performance indicators and outcomes should be provided to the *Regulators* in the annual safety and environmental reports as referenced in sections 182, 186, 200 and 201 of the *Framework Regulations*, as applicable.

PART 4: AUTHORIZATION

APPLICATION

Section 8 – Application

Documents and information

8 The application for an authorization must be accompanied by the following documents and information:

(a) the scope of the proposed work or activity;

(b) an execution plan and schedule for undertaking the proposed work or activity;

(c) the safety plan referred to in section 9;

(d) the environmental protection plan referred to in section 10;

(e) the contingency plan referred to in section 11;

(f) a description of the installations, including their systems and equipment, pipelines, vessels and support craft, that are to be used for carrying out the work or activity, including the layouts of the installations;

(g) in the case of a production project, a description of the field data acquisition program referred to in section 13;

(h) in the case of a drilling program or a production project,

> ***(i) information on***
>
> > ***(A) any proposed flaring or venting of gas, including the rationale for flaring or venting and the estimated rate, quantity and period of the flaring or venting, and***
> >
> > ***(B) any proposed burning of oil, including the rationale for burning and the estimated quantity of oil proposed to be burned, and***
>
> ***(ii) the decommissioning and abandonment plan referred to in section 15;***

(i) in the case of a geoscientific program, geotechnical program or environmental program,

> ***(i) a map illustrating the location of the program works and activities and their proximity to any man-made structures or vulnerable natural structures, as well as any territorial or other boundaries,***
>
> ***(ii) a description of the methods to be used in carrying out the program works and activities and a description of any aircraft or vessel to be used, and***
>
> ***(iii) a description of the proposed data acquisition plan;***

(j) in the case of a diving project, the dive project plan required under section 171 of the Canada–Newfoundland and Labrador Offshore Area Occupational Health and Safety Regulations (or the Canada-Nova Scotia Offshore Area Occupational Health and Safety Regulations); and

(k) if applicable, the list required under paragraph 151(a), the records made in the course of conducting the risk assessment required under paragraph 151(b) and the action plan required under paragraph 151(c).

Guidance for Subsections

Pursuant to section 8 of the *Framework Regulations*, an application for an OA must be accompanied by the information that is prescribed to be submitted in the regulations and that is prescribed under the *Accord Acts*.

Guidance for each subsection is provided as follows:

a. Scope

Pursuant to paragraph 8(a) of the *Framework Regulations,* the application for an OA must clearly describe the scope of work and activities. Any activity conducted under an OA that has not been described as part of the application should not begin until it has been demonstrated and accepted by the *Regulator* that it can be carried out in a manner that ensures safety and protection of the environment. Some important points to consider:

- The scope must be reflective of activities related to the spatial (e.g., area) or temporal (e.g., timing) scope described in the associated *Development Plan* (if applicable), associated Environmental Assessments and Impact Assessments, the *Benefits Plan*, Financial Requirements documentation and the associated risk assessments that have been undertaken.
- It should include all associated transportation, installation, commissioning, operations, maintenance, inspection, testing, decommissioning, abandonment or removal associated with each activity being conducted, as applicable.
- It should list any installations, vessels or aircraft, and support craft (e.g., vessel, aircraft, tanker, ROV, RPAS) that are being used or are planned to be used as part of the activity.
- It should include the use of support services in support of the activity, such as medical services, environmental monitoring, ice monitoring, spill response, etc.
- For well operations on development wells, it should include any plans for batch drilling of conductor and surface hole sections of wells and should provide any clarity on activities to performed on a well that will not require submission of an ACW.
- Additional attention should be given to concurrent or simultaneous activities (e.g., SIMOPS) or operations being conducted pursuant to another authorization or that is being conducted outside of the *Regulator's* regulatory approval processes, such as fishing or research.
- All documentation submitted in support of the application for an OA must also be reflective of the scope. If the documentation submitted is not reflective of the scope, this may result in a condition being appended to the OA to prohibit the described scope until the updated information has been provided and accepted by the *Regulator*.
- Any other activity that is being carried out during the approved activity, such as observation of wildlife or studies (e.g., marine mammals, seabirds) should be specified.

b. Execution Plan and Schedule

Pursuant to paragraph 8(b) of the *Framework Regulations*, the application for an OA must be accompanied by an execution plan and schedule. The execution plan and schedule can either be embedded directly into the application for an OA itself or maintained as a separate controlled document that is referenced in the application for an OA. Long-term activities (e.g., production projects, multi-year authorizations) should maintain the execution plan and schedule as a separate controlled document. If several OAs are planned to be issued, the operator may reference the same execution plan and schedule for the entire project in each OA. The execution plan and schedule should include the following:

- Any commitments made in associated Environmental Assessments and Impact Assessments.
- Expected activities for the duration of the program, including any activities associated with construction, installation, commissioning, drilling, production, decommissioning, abandonment and removal, as applicable.
- Drilling programs should include the plan for drilling, completion, intervention, suspension or termination of each well.
- For production projects:
  - Any commitments made in the *Development Plan* and updated Resource Management Plan.
  - Any planned future turnarounds associated with major overhauls or comprehensive inspection of equipment.
  - Timeframes associated with the renewal of class, if applicable, and the expiry date of the COF.
  - The asset life of the installation.
  - Any activity that may be conducted in the future in support of the project and that may involve other installations or vessels (e.g., diving, construction, intervention).

The operator is expected to update the *Regulator* regarding any changes in the execution plan or schedule. The schedule should also be consistent with the annual schedule (e.g., Regulatory Activity Plan) that is submitted to the *Regulator* as part of the Cost Recovery Letter of Intent.

c. Safety Plan

Pursuant to paragraph 8(c) of the *Framework Regulations*, an application for an OA must be accompanied by a Safety Plan. Refer to the guidance provided under section 9 of the *Framework Guideline* and the *Safety Plan Guideline*.

d. Environmental Protection Plan

Pursuant to paragraph 8(d) of the *Framework Regulations*, the application for an OA must be accompanied by an Environmental Protection Plan. Refer to the guidance provided under section 10 of the *Framework Guideline* and the *Environmental Protection Plan Guideline*.

e. Contingency Plan

Pursuant to paragraph 8(e) of the *Framework Regulations*, an application for an OA must be accompanied by a Contingency Plan. Refer to the guidance provided under section 11 of the *Framework Guideline* and the *Contingency Plan Guideline*.

f. Description of Installations, Pipelines, Vessels and Support Craft

Pursuant to paragraph 8(f) of the *Framework Regulations*, an application for an OA must be accompanied by a description of the installations, pipelines, vessels, support craft and all other equipment or systems to be used, as well as a layout of any installations used. The following should be noted:

- **All programs**

  A description of all equipment in relation to safety or environmental protection must be included in the Safety Plan and the Environmental Protection Plan pursuant to sections 9 and 10 of the *Framework Regulations*. Rather than repeat this information in the application for an OA, a direct reference to the Safety Plan and Environmental Protection Plan should be included.

- **Drilling Programs**

  For an installation that conducts drilling activities, the Safety Plan and Environmental Protection Plan should include any technical specifications and parameters (excluding specifics such as make, model and other details subject to change during replacement of equipment) specified in the *IADC Equipment List*. The *IADC Equipment List* itself should not accompany an application for an OA, but can be referenced in the Safety Plan and Environmental Protection Plan.

- **Installations**

  Pursuant to section 157 of the *Framework Regulations*, a description of equipment and its limitations must also be included in the Operations Manual for a production, drilling or accommodations installation. This document is not required to be submitted as part of the application for an OA unless it is being submitted as part of the Safety Plan and Environmental Protection Plan.

g. Field Data Acquisition Programs

Pursuant to paragraph 8(g) of the *Framework Regulations*, if production activity is being carried out as part of an application for an OA it must be accompanied by a FDAP. Refer to requirements and associated guidance under section 13 of the *Framework Regulations*.

h. Flaring or Venting of Gas or Burning of Oil

Pursuant to clauses 8(h)(i)(A) and 8(h)(i)(B) of the *Framework Regulations*, if drilling or production activity is being carried out as part of an the application for an OA it must be accompanied by information on any proposed flaring, venting of gas or burning of oil, including the rationale and the estimated rate, quantity and period of the flaring or venting of gas or burning of oil. Information can be included directly in the application for an OA or alternatively in a separate referenced document. Despite the approval noted above, any flaring, venting of gas or burning of oil is still required to meet the requirements of other authorities. In addition, any planned in situ burning in response to an oil spill should be described and approval may need to be obtained from other authorities prior to doing so.

If associated with a formation flow test, it should be conducted in accordance with the *Regulator*'s approval of this activity under section 63 of the *Framework Regulations*. Refer also to requirements in section 131 of the *Framework Regulations* in relation to gas release systems.

When the operator proposes to flare or vent gas on a continuous basis during a production project, the following should be included, when applicable:

- A discussion of the options considered to conserve the gas and why they were rejected;
- Period for which it is proposed to flare or vent gas and estimates of the flow rates and volumes proposed to be flared or vented;
- Discussion of any potential safety hazards and the precautionary measures to be taken; and
- Reference to associated plans or procedures (e.g., flare management plans).

While operators are given flexibility to operate within set flare volume limits, flaring volumes and practices are monitored on a continuous basis to ensure that good flaring and venting management practices are in place at each producing facility.

i. Decommissioning and Abandonment Plan

Pursuant to paragraph 8(h)(ii) of the *Framework Regulations*, if drilling or production activity is being carried out as part of an application for an OA it must be accompanied by a decommissioning and abandonment plan. With respect to exploration and delineation drilling, this should include measures to remove any installed equipment, to terminate and abandon wells and to restore the site, whereas for production or other fixed installations, more detailed plans would need to be submitted. Refer to the requirements and associated guidance for decommissioning and abandonment plans under section 15 of the *Framework*

Regulations. For well suspensions and terminations, refer to the requirements and associated guidance under sections 90 – 93 of the *Framework Regulations*. For any infrastructure or equipment planned to be left on or attached to the seabed, information must be provided to the *Regulator* for review and discussion with other agencies.

j. Geoscientific, Geotechnical or Environmental Programs

Pursuant to paragraph 8(i) of the *Framework Regulations*, activities related to a geoscientific, geotechnical or environmental activity must be described. This includes any activity that may be carried out from the installation or associated support craft such as well site surveys, VSPs, environmental monitoring or sampling, etc. The program description should include the following:

- A detailed description of the aims and objectives of the proposed program and any relevant supporting documentation. For example, for geoscientific programs involving seismic, relevant documentation would include descriptions of source and receiver equipment, including geometry and configuration, peak pressure and rise time of source and acquisition parameters; and
- The map of the areal extent should include the relationship to the land interests in the area, neighboring coastlines, provincial or territorial boundaries, the associated Environmental Assessment and Impact Assessment project area and other pertinent geographic features. For geoscientific programs, a digital shapefile of the proposed survey should be included in a format applicable to the survey type (e.g., 3D bin grid, 3D full fold outlines and polygon outlines for 3D seismic programs, lines for 2D seismic programs and points for sample locations). All maps should reference NAD 83.

k. Diving Projects

Pursuant to paragraph 8(j) of the *Framework Regulations*, activities related to a diving project must be described and a dive project plan must accompany the application. This would include any activity that may be carried out from the installation or associated support craft. Operators should refer to the requirements and associated guidance on diving activities under Part 9 of the *Framework Regulations* and Part 32 of the *OHS Regulations.* As a number of the submission requirements are the same as for the Safety Plan, the dive project plan can form part of the Safety Plan submission and as such, details need not be repeated between these documents.

l. IMO Decisions and Exemptions

No guidance required at this time. Refer to the requirements under section 151 of the *Framework Regulations* for foreign flagged floating platform (drilling, production or accommodations installations).

Additional Guidance

In NL, additional guidance for applications for authorizations are provided in the *Guideline for Petroleum-Related Authorizations and Approvals*. In NS, contact the CNSOPB for guidance on other requirements for OAs.

Section 9 – Safety Plan

9 (1) An operator must develop a safety plan that sets out the procedures, practices, resources, sequence of key safety-related activities and monitoring measures that are necessary to safely carry out a proposed work or activity, as well as the target levels of safety in respect of the work or activity and measures for hazard management.

Documents and information

(2) The safety plan must include the following documents and information:
(a) specific references to and detailed descriptions of the provisions of the management system that relate to safety, sufficient to demonstrate how the obligations set out in these Regulations with regard to safety will be fulfilled;
(b) a document that includes
- ***(i) a summary of the studies that have been carried out, and a description of the processes that will be followed, for the purposes of***
  - ***(A) identifying hazards related to the proposed work or activity that may occur during routine and non-routine operations, including any hazards posed by any other activities taking place near the proposed work or activity, and***
  - ***(B) assessing safety risks associated with the identified hazards,***
- ***(ii) a description of the identified hazards referred to in clause (i)(A) and the results of the assessments referred to in clause (i)(B),***
- ***(iii) a summary of the measures to be implemented to anticipate safety risks related to the identified hazards,***
- ***(iv) a summary and evaluation of the measures to be implemented to reduce the safety risks associated with the identified hazards, including, if the possibility of ice hazards exists, measures for ice detection, forecasting, surveillance and reporting, including data collection, and any measures for ice avoidance or deflection,***
- ***(v) a detailed description of the measures to be implemented to reduce safety risks to a level that is as low as reasonably practicable in respect of***
  - ***(A) the design of all installations, including their systems and equipment,***
  - ***(B) the design, winterization and operation of any installation that is to be operated in a cold climate,***
  - ***(C) the design, arrangement, installation and maintenance of barriers to provide fire and blast protection,***
  - ***(D) the design of all control systems,***

(E) the design, selection, location, installation, commissioning, protection, operation, inspection and maintenance of mechanical equipment,

(F) the design, construction, installation, commissioning, operation, inspection, monitoring, testing and maintenance of any subsea production system under all foreseeable physical and environmental conditions and operating conditions for all modes of operation,

(G) the management of temporary or portable equipment, and

(H) the arrangement and specification of watertight and weathertight appliances,

(vi) a detailed description of the measures to be implemented in respect of

(A) the design and location of any vent that is used to release gas into the atmosphere without combustion in order to minimize the risk of accidental ignition of the gas,

(B) the design, selection, operation, inspection, testing and maintenance of fire protection systems and equipment in order to minimize the risk of hazards to persons who use those systems and equipment,

(C) the design of boilers and pressure systems in order to minimize the risk of hazards to the installation and to persons present on it and to any other installations, vessel or persons in proximity to it, and

(D) the design and maintenance of any disconnectable mooring system on a floating platform to ensure that the risk that the system will fail to safely disconnect if exposed to situations that would exceed the platform's structural limits or the system's design limits is reduced to a level that is as low as reasonably practicable, without compromising the ability to achieve the target levels of safety set out in the safety plan and environmental protection plan, and

(vii) a summary of the measures to be implemented for communicating the identified hazards and for mitigating the safety risks associated with those hazards to all persons who are directly affected;

(c) a description of all installations or vessels that are to be used during the proposed work or activity, a description of their systems and equipment that are critical to safety and a brief description of the systems in place for the inspection, testing and maintenance of those systems and that equipment;

(d) a description of the organizational structure and chain of command for the proposed work or activity that

(i) explains the relationship between the organizational structure and chain and command, and

(ii) includes the name, position and contact information of the employee who is responsible for the management of the safety plan; and

(e) a description of the measures to be implemented to monitor compliance with the plan and to evaluate performance in relation to its objectives.

Submission

- A Safety Plan is required to be submitted to the *Regulator* as part of the application for an OA according to section 8 of the *Framework Regulations*.
- Refer also to the requirements respecting implementation under section 50 of the *Framework Regulations*.
- The Safety Plan may also make reference to details provided in the Contingency Plan and Environmental Protection Plan. It can also include as part of the submission, the Marine Operations Manual required by flag state, if applicable.
- As many of the requirements between sections 9 and 10 of the *Framework Regulations* are the same, the Safety Plan and the Environmental Protection Plan can be combined as long as all details are captured in the document or suite of documents that are submitted.

Objectives

The Safety Plan should also meet the following objectives:

- Demonstrate compliance to the *Accord Acts* and regulations and any other requirements of the *Regulator*, such as safety-related commitments within *Development Plans* and any conditions of associated Decision Reports (for activities associated with production projects).
- Include any commitments of the application for an OA, associated approvals, health and safety or operational safety related RQs and any conditions, if applicable.
- Demonstrate compliance to associated safety-related commitments or conditions of associated Environmental Assessments and Impact Assessments.
- Demonstrate compliance to the requirements of other authorities, as applicable.
- Reflect the scope of activities to be performed under the authorization including transportation, construction, installation, commissioning, operations, preservation, decommissioning and abandonment, as applicable. It should also include any associated support and resources, as applicable.
- Describe the plans and procedures in place to protect the health and safety of persons during the conduct of that work or activity.
- Be written such that it can be used by any person (e.g., employers, employees, suppliers, providers of service) involved in the program, whether they are located onshore or offshore and to provide reference to where more detailed information can be obtained.
- Be organized in a manner that provides effective and clear guidance.
- Contain information that is specific, measurable, achievable, relevant and auditable.

Guidance

- Detailed guidance on the information to be included in the Safety Plan submission is provided in the *Safety Plan Guideline.*
- In the case of a drilling program using a MODU, an operator can include as part of its Safety Plan submission, all or part of, the HSE Case developed in accordance with the *IADC HSE Case Guideline for Mobile Offshore Drilling Units.*

- In the case of an onshore-to-offshore drilling operation, an operator can include as part of its Safety Plan submission, all or part of, the HSE Case developed in accordance with the *IADC HSE Case Guideline for Land Drilling Units.*
- In the case of a dive project, an operator should submit the Dive Project Plan referred to in section 171 of the *OHS Regulations* as part of its Safety Plan submission. A Dive Project Plan must be submitted pursuant to paragraph 8(j) of the *Framework Regulations*.
- Guidance for HSE plans for marine operations is also provided in *ISO 19901-6 Petroleum and natural gas industries - Specific requirements for offshore structures - Part 6: Marine operations.*

Updates

The Safety Plan forms part of the application for an OA. As such, the document or documents submitted to meet the requirements for a Safety Plan and the commitments made in those documents will remain enforceable until the operator submits an amended document for *Regulator* review, and that amended document is accepted by the *Regulator*. Once acceptable, the *Regulator* will amend the authorization to replace the previous version with the one submitted.

Section 10 – Environmental Protection Plan

10 (1) An operator must develop an environmental protection plan that sets out the procedures, practices, resources and monitoring measures that are necessary to protect the environment from the effects of a proposed work or activity, the target levels of safety in respect of the work or activity and measures for hazard management.

Documents and information

(2) The environmental protection plan must include the following documents and information:
(a) specific references to and detailed descriptions of the provisions of the management system that relate to the protection of the environment, sufficient to demonstrate how the obligations set out in these Regulations with regard to environmental protection will be fulfilled;
(b) a document that includes

> ***(i) a summary of the studies that have been carried out, and a description of the processes that will be followed, for the purposes of***
>
> > ***(A) identifying hazards related to the proposed work or activity that may occur during routine and non-routine operations, including any hazards posed by any other activities taking place near the proposed work or activity, and***
> > ***(B) assessing environmental risks associated with the identified hazards,***
>
> ***(ii) a description of the identified hazards referred to in clause (i)(A) and the results of the assessments referred to in clause (i)(B),***

(iii) a summary of the measures to be implemented to anticipate environmental risks related to the identified hazards,

(iv) a summary and evaluation of the measures to be implemented to reduce the environmental risks associated with the identified hazards, and

(v) a detailed description of the measures to be implemented to reduce environmental risks to a level that is as low as reasonably practicable in respect of

(A) the design of all installations, including their systems and equipment,

(B) the design, winterization and operation of any installation that is to be operated in a cold climate,

(C) the design, arrangement, installation and maintenance of barriers to provide fire and blast protection,

(D) the design of all control systems,

(E) the design, selection, location, installation, commissioning, protection, operation, inspection and maintenance of mechanical equipment,

(F) the design, construction, installation, commissioning, operation, inspection, monitoring, testing and maintenance of any subsea production system under all foreseeable physical and environmental conditions and operating conditions for all modes of operation, and

(G) the management of temporary or portable equipment, and

(vi) a detailed description of the measures to be implemented in respect of the design and location of any vent that is used to release gas into the atmosphere without combustion in order to minimize the risk of accidental ignition of the gas, and

(vii) a summary of the measures to be implemented for communicating the identified hazards and for mitigating the environmental risks associated with those hazards to all persons who are directly affected;

(c) a description of all installations or vessels that are to be used during the proposed work or activity, a description of their systems and equipment that are critical to the protection of the environment and a brief description of the systems in place for the inspection, testing and maintenance of those systems and that equipment;

(d) in the case of a drilling program or a production project, the procedures for the selection, evaluation and use of chemical substances, including process chemicals and drilling fluid ingredients;

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

(f) a description of all of the discharge streams and the limits of any discharge into the environment, including any discharge of waste material;

(g) a description of the system for monitoring compliance with the discharge limits referred to in paragraph (f), including the sampling and analytical programs for determining whether discharges are within the specified limits;

(h) a description of the organizational structure and chain of command for the proposed work or activity that

(i) explains the relationship between the organizational structure and chain of command, and

(ii) includes the name, position and contact information of the employee who is responsible for the management of the environmental protection plan;

(i) a description of the measures to be implemented to monitor compliance with the plan and to evaluate performance in relation to its objectives; and

(j) a description of the procedure to be followed if an archaeological site or a burial ground is discovered during the proposed work or activity.

Submission

- An Environmental Protection Plan is required to be submitted to the *Regulator* as part of the application for an OA according to section 8 of the *Framework Regulations*.
- Refer also to the requirements respecting implementation under section 50 of the *Framework Regulations*.
- The Environmental Protection Plan may make reference to details provided in the Contingency Plan and Safety Plan. It can also include as part of the submission, the Marine Operations Manual required by flag state, if applicable.
- As many of the requirements between sections 9 and 10 of the *Framework Regulations* are the same, the Safety Plan and the Environmental Protection Plan can be combined as long as all details are captured in the document or suite of documents that is submitted.

Objectives

The Environmental Protection should also meet the following objectives:

- Demonstrate compliance to the *Accord Acts* and regulations and any other requirements of the *Regulator*, such as environment-related commitments within *Development Plans* and any conditions of associated Decision Reports (for activities associated with production projects).
- Include any commitments of the application for an OA, associated approvals, environmental related RQs and conditions, if applicable.
- Demonstrate compliance to associated environmental commitments or conditions of associated Environmental Assessments and Impact Assessments.
- Demonstrate compliance to the requirements of other authorities, as applicable.
- Reflect the scope of activities to be performed under the authorization including transportation, construction, installation, commissioning, operations, preservation, decommissioning and abandonment, as applicable. It should also include any associated support and resources, as applicable.
- Describe the plans and procedures in place to protect the environment during the conduct of that work or activity.
- Be written such that it can be used by any person (e.g., employers, employees, suppliers, providers of service) involved in the program, whether they are located onshore or offshore, to direct their work and to provide reference to where more detailed information can be obtained.
- Be organized in a manner that provides effective and clear guidance.

- Contain information that is specific, measurable, achievable, relevant and auditable.

Guidance

- Detailed guidance on the information to be included in the Environmental Protection Plan submission is provided in the *Environmental Protection Plan Guideline*.
- In the case of a drilling operation using a MODU, an operator can include as part of its Environmental Protection Plan submission, all or part of, the HSE Case developed in accordance with the *IADC HSE Case Guideline for Mobile Offshore Drilling Units.*
- In the case of an onshore-to-offshore drilling operation, an operator can include as part of its Environmental Protection Plan submission, all or part of, the HSE Case developed in accordance with the *IADC HSE Case Guideline for Land Drilling Units.*
- Guidance for HSE plans for marine operations is also provided in *ISO 19901-6 Petroleum and natural gas industries - Specific requirements for offshore structures - Part 6: Marine operations.*
- In the case of a drilling program or a production project, with respect to paragraph 10(2)(d) of the *Framework Regulations,* the operator should have procedures in place for the selection, evaluation and use of chemical substances. Guidance is provided in the *Offshore Chemical Selection Guideline.*
- With respect to paragraph 10(2)(e) of the *Framework Regulations,* refer to guidance provided in the *Offshore Discharge Guideline.*
- With respect to paragraph 10(2)(j) of the *Framework Regulations*, while associated Environmental Assessments and Impact Assessments should identify if potential archeological or burial sites are present, the operator should also have a procedure in place in the event that potential archeological or burial sites are located. The following guidance is provided with respect to the contents of such a procedure:
  - With respect to the discovery of an archeological site – there is no pan-Canadian legislation to establish a process to protect, conserve, document and exhibit archaeological resources on federal land and under waters of federal responsibility. The provincial archeologist[14] should be contacted to provide guidance on appropriate procedures to be adopted by an operator to prevent damage to an archeological discovery.
  - With respect to discovery of a burial site – the discovery of human remains – interference with human remains is an indictable offence under section 182 of the *Criminal Code* and the RCMP should be contacted immediately to determine whether the discovery is:
    - a crime scene; or
    - something else (e.g., an unrecorded but non-criminal burial site or an archaeological site). In this case, the RCMP will normally contact the provincial archaeological service.

[14] In NL, refer to contact information at https://www.gov.nl.ca/tcar/contact/arts-and-culture-branch/#pao; In NS, refer to contact information at https://cch.novascotia.ca/exploring-our-past/special-places/archaeology-permits-and-guidelines

Updates

The Environmental Protection Plan forms part of the application for an OA. As such, the document or documents submitted to meet the requirements for an Environmental Protection Plan and the commitments made in those documents will remain enforceable until the operator submits an amended document for *Regulator* review, and that amended document is accepted by the *Regulator*. Once acceptable, the *Regulator* will amend the authorization to replace the previous version with the one submitted.

Section 11 – Contingency Plan

11 (1) An operator must develop a contingency plan that sets out the procedures, including emergency response procedures, and the practices, resources and monitoring measures that are necessary to effectively prepare for and mitigate the effects of any accidental event.

Documents and information

(2) The contingency plan must include the following documents and information:
(a) a description of the method to be used for classifying accidental events and a description of the emergency response procedures for each event;
(b) a description of the procedures for the internal and external reporting of accidental events;
(c) a description of the procedures for accessing safety-related and environmental information that is necessary to mitigate the effects of any accidental event;
(d) a description of the organizational structure, chain of command and resources for managing any accidental event, including

> ***(i) a list of key emergency response positions and a description of the roles, responsibilities and authorities associated with each of those positions, including a description of related tasks and checklists of actions that must be taken in the context of the contingency plan,***
> ***(ii) a description of the available support craft and the contact information for its crew or a reference to the number or title of a document that provides that description and contact information,***
> ***(iii) a description, or a reference to the number or title of a document that provides the description, of available emergency response equipment, including life-saving appliances, and the equipment's location, as well as the limits on its use and the mitigation measures to be taken in the event that it is not available,***
> ***(iv) a description, or a reference to a number or title of a document that provides the description, of all available medical equipment and the equipment's location,***
> ***(v) a description of the communication system referred to in section 129 and the operating procedures for that system,***
> ***(vi) a description of all emergency response operations centres and their locations,***
> ***(vii) a description of any good or service that must be obtained on a contractual basis for each response measure, and***

> *(viii) a description of the location and the contents of any temporary safe refuges or a reference to the number or title of a document that provides that description;*

(e) details of all mutual aid arrangements entered into with other operators;

(f) a description of the procedures for coordinating and liaising with all relevant emergency response organizations;

(g) a description of the communication protocols with all relevant federal, provincial, territorial and municipal agencies and Indigenous governing bodies;

(h) a copy of all personnel evacuation plans, including any evacuation plan for divers engaged in a dive; and

(i) an indication of the frequency with which emergency response drills and exercises are to be completed and their scope.

Uncontrolled Flow

(3) In the case of a drilling program or a production project, the contingency plan must also include a description of the source control and containment measures to be taken to stop uncontrolled flow from a well and to minimize the duration and environmental effects of any resulting spill, as well as the following documents and information:

(a) a description of the source control and containment equipment to be used in the event of a loss of well control;

(b) details of the contractual arrangements for the source control and containment equipment, other than a relief well drilling installation, including

> ***(i) the name and contact information of the owner or owners of the equipment,***
>
> ***(ii) the arrangements for transport of the equipment to the location of the uncontrolled well, and***
>
> ***(iii) the arrangements for the mode of deployment of the equipment at the location of the uncontrolled well;***

(c) the schedule and plan for the mobilization, deployment and operation of the source control and containment equipment, including measures to minimize deployment time that take required regulatory approvals into account;

(d) details regarding the accessibility of the source control and containment equipment and the documents and information referred to in paragraphs (a) to (c);

(e) an explanation of the adequacy of each of the source control and containment measures; and

f) a description of any support systems and equipment that are available, including vessels and remotely operated vehicles and any consumables that may be used, such as, in the case of a relief well, a spare wellhead, spare casing and spare bulk additives.

Spill-treating agent

(4) If a spill-treating agent is being considered for use as a spill response measure, the contingency plan must include the following additional documents and information:

(a) the name of the chosen spill-treating agent and details of an assessment of its efficacy in treating the potential sources of pollutants, including the results of any tests conducted for the assessment and a description of those tests;
(b) the results of an analysis that demonstrates that a net environmental benefit is likely to be achieved through the use of the spill-treating agent under certain circumstances;
(c) a description of the circumstances under which the spill-treating agent will be used and the estimated period within which its use will be effective;
(d) a description of the methods and protocols, including the amount and application rate, for safe, effective and efficient use of the spill-treating agent;
(e) a list of the personnel roles, equipment and materials that an operator will have available for the purpose of using the spill-treating agent, including any to be provided through contractual arrangements, and a description of the requirements that must be met for those contracts to be activated; and
(f) a monitoring plan for the use of the spill-treating agent.

Assessment of efficacy

(5) The assessment of efficacy under paragraph (4)(a) must be carried out using oil obtained directly from the operations site where the spill-treating agent is being considered for use or, if oil is not available from that operations site, it must be carried out using an oil that most closely resembles the oil that is expected to be obtained from the operations site and must be repeated when oil becomes available from that operations site.

International standard or alternative

(6) The assessment, analysis, methods and protocols referred to in paragraphs (4)(a), (b) and (d) must be based, taking the local environment into account, on an international standard or an alternative recognized by the Board and the contingency plan must identify each of those standards or alternatives.

Methods and protocols

(7) The methods and protocols referred to in paragraph (4)(d) and the monitoring plan referred to in paragraph (4)(f) must conform to industry standards and best practices for spill-treating agent use, taking the local environment into account.

Definition of source control and containment equipment

(8) In this section, source control and containment equipment means the capping stack, containment dome, any subsea and surface equipment, devices or vessels and any relief well drilling installations that are used to contain and control a spill source and to minimize the duration of a spill and its environmental effects until well control is regained.

Submission

- A Contingency Plan is required to be submitted to the *Regulator* as part of the application for an OA according to section 8 of the *Framework Regulations*.
- Refer also to the requirements respecting implementation under section 50 of the *Framework Regulations*.
- The Contingency Plan may also make reference to details provided in the Safety Plan and Environmental Protection Plan.

Objectives

The Contingency Plan should also meet the following objectives:

- Demonstrate compliance to the *Accord Acts* and regulations and any other requirements of the *Regulator*, such commitments within *Development Plans* and any conditions of associated Decision Reports (for activities associated with production projects).
- Include any commitments of the application for an OA, associated approvals, related RQs and any conditions, if applicable.
- Demonstrate compliance to associated commitments or conditions of associated Environmental Assessments and Impact Assessments.
- Demonstrate compliance to the requirements of other authorities, as applicable.
- Reflect the scope of activities to be performed under the authorization including transportation, construction, installation, commissioning, operations, preservation, decommissioning and abandonment, as applicable. It should also include any associated support and resources, as applicable.
- Be written such that it can be used by any person (e.g., employers, employees, suppliers, providers of service) involved in the program, whether they are located onshore or offshore, to direct their work and to provide reference to where more detailed information can be obtained.
- Be organized in a manner that provides effective and clear guidance.
- Contain information that is specific, measurable, achievable, relevant and auditable.

Guidance

- Detailed guidance on the information to be included in the Contingency Plan submission is provided in the *Contingency Plan Guideline.*
- Additional guidance on Contingency Plans, emergency response procedures, drills, etc. are provided in the following references:
  - SOLAS and classification society rules provide some requirements and guidance on contingency plans, emergency response procedures, drills, etc. It should be noted that these references do not include all non-marine emergency response equipment or hazards introduced by non-marine related operations, so these require additional consideration.

- *ISO 15544 Oil and gas industries – Offshore production installations – Requirements and guidelines for emergency response*.
- *IADC HSE Case Guidelines for Mobile Offshore Drilling Units.*

Updates

The Contingency Plan forms part of the application for an OA. As such, the document or documents (e.g., Emergency Response Plan, Oil Spill Response Plan, Well Control Policy, Vessel Traffic Management Plan) submitted to meet the requirements for a Contingency Plan and the commitments made in those documents will remain enforceable until the operator submits an amended document for *Regulator* review, and that amended document is accepted by the *Regulator*. Once acceptable, the *Regulator* will amend the authorization to replace the previous version with the one submitted.

Section 12 – Spill-treating agent — the Act

12 In determining for the purpose of section 138.21 (or 142.21) of the Act whether the use of a spill-treating agent is likely to achieve a net environmental benefit, the Board must take into account
(a) the assessment of the spill-treating agent's efficacy referred to in paragraph 11(4)(a);
(b) the results of the analysis referred to in paragraph 11(4)(b);
(c) the circumstances referred to in paragraph 11(4)(c);
(d) the methods and protocols referred to in paragraph 11(4)(d); and
(e) the monitoring plan required referred to in paragraph 11(4)(f).

Guidance is provided in the *Contingency Plan Guideline*.

Section 13 – Field Data Acquisition Program

13 In the case of a production project, the operator must develop a field data acquisition program that
(a) provides for the collection of sufficient pool pressure measurements, drill cutting and fluid samples, cores and well logs, and the carrying out of sufficient formation flow tests, analyses and surveys, to enable a comprehensive assessment of the field, of the performance of development wells, of the pool depletion scheme and of any injection scheme; and
(b) identifies the quantity of samples and cores, the evaluation data and any associated analyses, surveys and reports that are to be provided to the Board.

The FDAP must either accompany the application for an OA, or in the case in which the program is already approved, the application must reference the document(s) submitted in support of this approval and the date of the *Regulator*'s approval. Guidance for these programs is provided in the *Data Acquisition Guideline*.

Section 14 – Flow System, Calculation and Allocation

14 (1) If the application for an authorization is in respect of a production project, the operator must 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 sections 74 to 78, as well as any alternate measurements referred to in subsection 74(2) that the operator proposes to conduct.

Board approval

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

Flow System and Flow Calculation Procedure

The flow system and flow calculation procedure describes how quantities of oil, gas and water are measured. It gives details of measurement procedures for volumes that are produced from or injected into each well in a pool or zone, as well as, volumes used as fuel, used for artificial lift or disposed of.

Flow Allocation Procedure

The flow allocation procedure describes how the total measured quantities of oil, gas and water produced from or injected into a pool or a zone are allocated during a reporting period back to individual wells in a pool, where individual well production or injection is not measured separately. This procedure should be referenced within the application for an OA and forms part of the documentation submitted in support of the application, and as such, should be controlled. Any proposed changes should be discussed with the *Regulator* prior to implementation. Guidance is provided in the *Measurement Guideline*.

General

Refer to the requirements and additional guidance on pools and zones in section 60 of the *Framework Regulations*.

Section 15 – Decommissioning and Abandonment Plan

15 (1) An operator must, in the case of a drilling program or production project, develop a decommissioning and abandonment plan that includes the following information:
(a) a description of the safety and environmental protection measures to be implemented during the decommissioning and abandonment to comply with the requirements of these Regulations, the provisions of Part III of the Act and any federal or provincial legislation or international conventions or agreements relating to safety and the protection of the environment;
(b) a description of the potential effects of the decommissioning and abandonment on the environment and on any other uses of the site where the program or project is carried out;
(c) the methods for restoring the site after the decommissioning and abandonment; and
(d) the forecasted costs of the decommissioning and abandonment and the manner in which the operator will finance or pay for those costs.

Costs and financing or payment

(2) The operator must submit to the Board an update on the forecasted costs of decommissioning and abandonment and the manner in which the operator will finance or pay for the costs
(a) whenever there is a significant change to that information, and
(b) beginning no less than five years before the day on which the decommissioning and abandonment is forecasted to begin, at least once a year.

General

Refer to the definition of "decommissioning and abandonment" under section 1 of the *Framework Regulations*.

a. Exploration and Delineation Drilling Programs

In the case of exploration or delineation drilling programs, a separate decommissioning and abandonment plan does not need to be submitted. The planned measures to remove any installed equipment, to terminate and abandon wells and to restore the site can be described in the application for an OA or the associated approvals. Refer to the requirements and associated guidance under sections 90 - 93 of the *Framework Regulations*. For any infrastructure or equipment planned to be left on or attached to the seabed, information should be provided to the *Regulator* for review and discussion with other agencies.

The measures to decommission and abandon these wells must also comply with the requirements of any Decision issued by the Minister of ECCC in respect of that drilling program, or in NL, for exploratory drilling, the *Regulations Respecting Excluded Physical Activities (Newfoundland and Labrador Offshore Exploratory Wells*), as the case may be.

b. Production Projects

In the case of a production project, any decommissioning and abandonment plan must comply with the commitments made in any associated Environmental Assessments and Impact Assessments and the requirements of any related Decision Statement issued by the Minister of ECCC in respect of that project. The plan must also address any commitments made in the *Development Plan* and any associated conditions in the *Development Plan* approval.

If decommissioning and abandonment was not subject to a thorough Environmental Assessment during a process completed under the *Accord Acts* or CEAA or the Impact Assessment under the IAA, or if the proposed plan differs materially from the plan that was assessed, it will be necessary to conduct either an Environmental or Impact Assessment of the plan for decommissioning and abandonment. Once a plan is developed, the operator should consult with the *Regulator* and the IAAC to determine what type of assessment will be required and which authority, the *Regulator* or IAAC, will conduct the assessment.

The decommissioning and abandonment plans must consider any:

- requirements of international conventions or agreements (e.g., UNCLOS Part 5, Article 60; *IMO Resolution A.672(16) Guidelines and standards for the removal of offshore installations and structures on the continental shelf and in the exclusive economic zone,* OSPAR Convention*)*; and
- federal and provincial legislative or regulatory requirements (e.g., associated laws on removal and disposal of facilities, associated laws on handling and disposal of waste material).

The aim of any decommissioning and abandonment plan is to restore the site to the condition described in the Development Plan and the environmental assessment processes completed under the *Accord Acts*, CEAA or the IAA, as the case may be . Refer also to the requirements and associated guidance provided for sections 90 - 93 and 120 of the *Framework Regulations.*

As referred to in paragraph 8(b) of the *Framework Regulations*, the execution plan and schedule should indicate when decommissioning and abandonment activities, including the abandonment of individual wells, are expected to start. For any planned decommissioning activities, the operator should begin updating the documents to be submitted in support of an authorization for that activity, including risk assessments and other supporting information, well ahead of the planned start of decommissioning. The *Regulator* suggests that this process is initiated five years before that application is made. Updates to referenced plans should be provided at appropriate intervals leading up to start of decommissioning, as changes in required resources and risks are identified.

At the end of the operational life of a well drilled as part of a production project, if it is shut-in and there is no plan for re-purposing the well, then the well should be planned for abandonment as soon as possible but no longer than five years after its use has ceased. The strategy for managing reservoir abandoned wells can be discussed with the *Regulator* on a case-by-case basis. With respect to the suspension and termination of wells, refer also to the requirements and associated guidance under sections 90 - 93 of the *Framework Regulations*.

The final decommissioning and abandonment plans should:

- Include a thorough discussion of hazards identified, risk assessment and proposed measures as required by paragraph 4(1)(m) of the *Framework Regulations*. This should include:
    - A description of the major accident hazards, OHS or environmental hazards and the associated contingency plans in place.
    - A description of the potential effects of the decommissioning and abandonment on the environment and on other uses and users of the environment. The measures and methods that will be taken to minimize adverse effects on navigation, other maritime operations and the marine environment during and post decommissioning must be included.
    - Appropriate surveys of the area should be undertaken to address any changes that may have occurred since the original surveys were completed. Pursuant to section 43 of the *Framework Regulations*, the proposed location of any infrastructure or equipment on or attached to the seabed, including any abandoned installation or part thereof must be provided.
    - An assessment of the condition of the installation at the time of decommissioning and abandonment to determine that the associated decommissioning and abandonment activities can be carried out safely.
    - If the production installation is planned to be removed and decommissioned prior to full field decommissioning, details related to subsea monitoring of wells and preservation until the time at which the wells can be fully decommissioned should be provided.
    - A description of the sequence of cleaning, flushing and the removal of materials (including hazardous substances), equipment and installations, and any measures that will be needed in the interim to ensure the safety of persons and protection of the environment until activities have been completed.
    - A description of the associated asset integrity program in place in the interim, which covers equipment and installations that will continue to be used and any temporary equipment or systems that will need to be put in place. (e.g., structural, electrical, pressure systems, navigation, lighting, landing areas, fire and life safety systems).
    - With respect to paragraph 15(1)(b) of the *Framework Regulations* and the requirements of associated Environmental Assessments and Impact Assessments, if the operator is proposing to abandon any equipment or installation components on site, a description of

the studies and surveys that will be undertaken to verify that it will not be a navigation or fishing hazard, a description of the proposed as-left condition, and a plan to monitor, assess and mitigate any adverse impacts on the environment (associated with contaminants, disintegration, rusting, etc.), navigation or other uses of the sea. If any equipment or component of the installation is left, the operator is subject to residual liability.

  - A description of the impacts on nearby operations sites.

- Outline the documents that will need to be updated in support of an application for an OA and the changes needed to the management system (e.g., equipment, procedures, training) to address this activity. This should include a summary of information to be updated in the Safety Plan, Environmental Protection Plan and Contingency Plan as required by sections 9, 10 and 11 of the *Framework Regulations*, respectively.
- Provide detailed economic information and commercial commitments respecting resource conservation and optimization of timing of abandonment and decommissioning to ensure prevention of waste.
- Describe the resources that will be required to enable the removal of materials and equipment, including the types of vessels and equipment required to lift, tow or transport the equipment, materials or the installation. The operator should refer to *ISO 19901-6 Petroleum and natural gas industries – specific requirements for offshore structures – Part 6: Marine operations*, which provides guidance on the marine operations associated with the decommissioning, removal and disposal of installations and their components.
- Describe the methods for restoration of the site after decommissioning and abandonment is completed.
- Describe the post-abandonment monitoring measures for abandoned wells or equipment that will be undertaken and list the reports that will be provided. Post-abandonment monitoring measures should be planned for up to one year after abandonment has been completed. This should include consideration of additional monitoring/sampling for detection of leaks, etc. With respect to abandonment of wells, refer to the requirements and associated guidance under sections 90 - 93 of the *Framework Regulations*. With respect to the abandonment of equipment, refer to the requirements and associated guidance under section 120 of the *Framework Regulations*. There may also be monitoring requirements arising from an associated Environmental Assessments and Impact Assessment completed for the project or the decommissioning and abandonment of the project.
- Provide the forecasted costs of decommissioning and abandonment related work or activity and the manner in which the operator will finance or pay for those costs.
- Describe the plans in place in the event that the removal of equipment or the installation cannot be conducted, and identify the regulatory authorities from which approval will be needed to be obtained to leave equipment in place. This should also describe any additional measures that need to be implemented post-abandonment.

REQUIREMENTS FOR AUTHORIZATION

Section 16 – Definitions

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16 (1) The following definitions apply for the purposes of paragraph 138(4)(c) (or 142(4)(c)) of the Act.

production facility means the systems and equipment referred to in paragraph (a) of the definition production installation, other than a diving system, as well as any associated aircraft landing areas, storage areas or tanks and accommodations areas.

production platform means a production installation.

No guidance required at this time.

WELL APPROVALS

Section 17 – Well Approvals

Well operation

17 (1) Subject to subsection (2), an operator that intends to conduct a well operation must obtain a well approval.

Approval not necessary

(2) A well approval is not necessary to conduct a wire line operation, slick line operation, coiled tubing operation or other similar operation through a tree located above sea level if
(a) the operation does not alter the completion interval or is not expected to adversely affect the recovery of petroleum; and
(b) the equipment, operating procedures and qualifications of the persons carrying out the work are in compliance with the requirements of the authorization.

(3) The following definitions apply in subsection (2).

slick line means a single steel cable that is used to run tools in 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.

Approval application contents

(4) The application for a well approval must include the estimated cost breakdown of the well operation and the following information:

(a) if the well approval sought is to drill a well,

> ***(i) a comprehensive description of the drilling program, a geoscientific description of the reservoir targets and a description of any geohazard,***
>
> ***(ii) the digital data necessary to allow for an independent geohazard assessment,***
>
> ***(iii) a description of the well data acquisition program referred to in section 18,***
>
> ***(iv) a description of the well verification scheme referred to in section 19;***

(b) if the well approval is being sought to perform a workover on, to re-enter, to complete or to recomplete a well or to suspend or abandon a well or a part of one, a description of the well or part, a description of the proposed work or activity and the rationale for carrying it out and barrier envelope diagrams that demonstrate that two barrier envelopes will be in place throughout the operation;

(c) if the well approval is being sought to complete a well, information that demonstrates that section 71 will be complied with;

(d) if the well approval is being sought to suspend a well or part of one, an indication of the period within which the suspended well or part will be abandoned or completed; and

(e) if the well approval is being sought to suspend or abandon a well or a part of one, the methods for verifying the effectiveness of the isolation of pools and zones that is required under subparagraph 90(1)(b)(i).

Well approval granted by the Board

(5) The Board must grant the well approval if the operator demonstrates that the well operation will be conducted safely, without waste or pollution and in compliance with these Regulations.

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a. General – Well Approvals

There are two types of well approvals issued by the *Regulator*:

- Approval to Drill a Well (ADW)
- Approval to Alter the Condition of a Well (ACW)

With respect to these approvals, the operator should also demonstrate that its programs comply with any associated *Development Plan* (for a production project), the associated Environmental Assessments and Impact Assessments, application for an OA or approval, and any associated conditions of a *Regulator* Decision, Decision Statement issued by the Minister of ECCC, and an OA or approval under the *Accord Acts*, as applicable. In NL, in the case of an exploration well that is to be drilled subject to the *Regulations Respecting Excluded Physical Activities (Newfoundland*

and Labrador Offshore Exploratory Wells), the operator must also comply with the requirements of those regulations.

In the case of a production project, where wells are similar, the application for an OA should capture any general commitments regarding the drilling, completion and intervention of the different types of wells to the extent practicable. It is not necessary to duplicate this information in subsequent approvals. Approval may be given by the *Regulator* to "batch-drill" or "pre-drill" the conductor hole section, or surface hole section of a well or wells prior to filing an ADW application as long as the relevant information is provided with the application for an OA.

For any well for which there is a high degree of uncertainty (e.g., exploration well) or high degree of risk (e.g., high risk criticality ranking as assigned in accordance with subsection 19(2) of the *Framework Regulations*) or if there is a new operator, it is recommended that consultations with the *Regulator* begin at least 9 - 12 months prior to the submission of information for the well approval. The operator may be requested to provide a presentation to the *Regulator* summarizing the geological prognosis, and any other drilling, safety, environmental and operational considerations for the well.

For high risk criticality ranking wells, which include deepwater wells, HPHT wells, wells expected to contain H_2S, or any other well where there may be increased concern regarding the safety of persons or protection of the environment, the *Regulator* may decide to implement special oversight measures throughout the well implementation process, including the planning, execution and termination of the well. Operators will be notified on a case-by-case basis of the decision to exercise special regulatory oversight. Special oversight measures are focused on well control protocols, equipment, competencies, blowout prevention and oil spill response contingency plans. There is a heightened focus on preventing kicks, maintaining two well barrier envelopes, assessing the extent of means in place for primary and secondary well control, and assessing the integrity and function of primary and secondary BOP systems. There is also heightened focus on assessing plans and processes for oil spill response readiness, relief well drilling arrangements and arrangements for capping stack/subsea containment systems. Additional information is provided in the paper presented at the Arctic Technology Conference in October 2016.[15]

The following interpretations are made with respect to the classification of wells:

- "deepwater" is interpreted to refer to water depths between 600 – 3000 m[16];
- "ultra deepwater" is interpreted to refer to water depths greater than 3000 m[17];
- "high pressure" is interpreted to refer to either the maximum pore pressure of any porous formation that exceeds an equivalent mud weight of 1.85 specific gravity or requires pressure control equipment with a rated working pressure in excess of 69 MPa[18]; and

[15] OTC-27352-MS - Special Oversight Measures for Deepwater and Critical Wells in Harsh Environments, M. Conway, October 24, 2016
[16] *NORSOK D-001 Drilling Facilities*
[17] *NORSOK D-001 Drilling Facilities*
[18] *Energy Institute Model Code of Practice: Part 17, Volume 1: High pressure and high temperature well planning*

- “high temperature” is interpreted to refer to bottom hole temperatures greater than 149°C[19].

Based on the well design, anticipated conditions, technology in use and the standards adopted for well operations, the operator may request or the *Regulator* may accept or request a classification different than that noted above. The *Regulator* may choose to implement special oversight measures based on a single parameter or a combination of parameters noted above.

b. Approval to Drill a Well (ADW)

The ADW covers operations on a well up to, and including, the termination of the well, which itself could include suspension, abandonment or completion. If all of the activities are not completed or covered during the initial ADW, future operations can be covered under an ACW subject to *Regulator* approval.

When an operator intends to drill a well, a completed **ADW Application Template** should be submitted as follows:

- Exploration, delineation or high risk wells: 60 days prior to spud
- Development wells: 21 days prior to spud

When permitted under an OA, approval may be given by the *Regulator* to batch-drill or pre-drill the conductor hole section, or surface hole section of development wells prior to filing an ADW application. In such cases the naming of a well(s) will not be assigned until such time that an ADW has been received documenting the target bottom-hole location of the well.

The **ADW Application Template** outlines the information to be submitted in accordance with the requirements of the *Framework Regulations*.

If the well is to be tested, an **Approval of a Formation Flow Test Program** is required pursuant to section 63 of the *Framework Regulations*. Refer to the associated guidance provided for this section of the *Framework Regulations.*

c. Deviations from the Approved ADW

In the event that it becomes necessary to deviate from details submitted as part of the approved ADW, a request should be made in writing explaining the change and the reason for the change to the *Regulator*.

In the event that it becomes necessary to deviate from the data acquisition programs referred to in sections 13 and 18 of the *Framework Regulations*, the operator should refer to the process for requesting deviations in the *Data Acquisition Guideline*.

[19] *Energy Institute Model Code of Practice: Part 17, Volume 1: High pressure and high temperature well planning*

d. Approval to Alter the Condition of a Well (ACW)

Following completion of the scope of activities covered by the ADW, and subject to the same general requirements for well approvals noted above, an ACW permits an operator to re-enter a well to perform any well operation described in that ACW. An ACW is required for any well operations through subsea trees and for platform wells if the conditions of subsection 17(2) of the *Framework Regulations* are not met. This could include a workover or the completion, re-completion, suspension, abandonment of a zone or well or other approved 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 described in the application for an OA, or is exempted pursuant to subsection 17(2) of the *Framework Regulations* (refer to additional guidance below). Operators should consult with the appropriate *Regulator* on a case-by-case basis if uncertainty exists whether an ACW is required.

Examples of activities that require an ACW include:

- Any well intervention on a subsea well.
- Any operation that affects a well barrier envelope (e.g., removal of the Christmas tree, removal of tubing).
- Any operation involving the suspension or abandonment of a zone or well, unless such operations were approved as part of the authorization.
- Any operation that alters the completion interval or that has the potential to adversely affect the recovery of petroleum including re-completing the well to another production or injection interval, squeezing perforations, chemical treatment, acid stimulation, hydraulic fracturing, etc.
- Any operation involving re-perforation of existing intervals.
- While not specifically meeting the definition of well operations, any change in status (e.g., sweet to sour) or change in use (e.g., production to injection) of the well will also require approval through the submission of an ACW.

e. Examples of activities Not Requiring an ACW

With respect to subsection 17(2) of the *Framework Regulations* and as approved as part of the authorization, the following through-the-tree well intervention operations on platform wells utilizing wire line, slick line or coiled tubing typically do not require an ACW:

- drift runs;
- cased hole logging;
- subsurface fluid sampling;
- pressure, temperature or spinner surveys;
- installation of pressure and temperature gauge hangers or gauges;
- chemical treatment for remedial or preventative purposes, such as acid wash and scale inhibition;
- introduction of chemical or radioactive tracers into injection wells;

- replacement of wing, swab or kill valves on surface Christmas trees if the tree is not removed; and
- maintenance of Christmas trees if the tree is not removed.

When an operator conducts activity that does not require an ACW, notification should be made to the *Regulator* via the daily report referred to in section 197 of the *Framework Regulations* prior to conducting the activity.

When an operator intends to alter the condition of a well, the **ACW Application Template** should be submitted a minimum of 21 days prior to the expected start of the operation.

The **ACW Application Template** outlines the information to be submitted in accordance with the requirements of the *Framework Regulations*.

f. Deviations from the Approved ACW

In the event that it becomes necessary to deviate from details submitted as part of the approved ACW, a request should be made in writing explaining the change and the reason for the change to the *Regulator*.

g. Notification to Suspend/Abandon and Notification to Complete

A **Notification to Abandon/Suspend** or a **Notification to Complete** should be provided no later than five working days prior to suspending, abandoning or completing any well. Prior to receiving acknowledgment to terminate a well (to complete, suspend or abandon a well or part of a well), the operator should provide such logs and data as may be requested by the *Regulator*. 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.

Some additional notes are as follows:

- As applicable, requirements for completion of wells are provided in section 71 of the *Framework Regulations* and requirements for the abandonment and suspension of wells are provided in sections 90 – 93 of the *Framework Regulations.* Information demonstrating compliance with these requirements should be provided to the *Regulator*.
- In the case of an exploration well that is to be drilled subject to the *Regulations Respecting Excluded Physical Activities (Newfoundland and Labrador Offshore Exploratory Wells)*, the operator must meet the requirements of those regulations.
- In cases in which a well is to be abandoned in a manner other than that described in the associated project specific Environmental Assessments and Impact Assessment the operator should consult with Indigenous and commercial fisheries that have fishing licences that, in the opinion of the DFO, overlap the activity area, and the operator should provide the results of that engagement to the *Regulator* for consideration.

- In the case in which the well is to be suspended (other than the short-term temporary suspension of operations because of physical and environmental conditions (including 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, plans for ongoing monitoring of the well and the expected timing for re-entry. If additional work is required to abandon the well in the future, these plans should also be described.

Section 18 – Well Data Acquisition Program

18 In the case of drilling program, an operator must develop a well data acquisition program that

(a) provides for the collection of sufficient pressure measurements, drill cutting and fluid samples, conventional cores, sidewall cores and well logs, and the carrying out of sufficient formation flow tests, analyses and surveys, to enable a comprehensive geophysical, geological and reservoir evaluation to be made; and

(b) identifies the quantity of samples and cores, the evaluation data and any associated analyses, surveys and reports that are to be provided to the Board.

A well data acquisition program (WDAP) must be included as part of the application for an ADW. Guidance for these programs is provided in the *Data Acquisition Guideline*.

Section 19 – Well Verification Scheme

19 (1) An operator must establish a well verification scheme based on criteria that the operator establishes to ensure that the design of any well is in accordance with industry standards and best practices so that the well's integrity is maintained throughout its life cycle.

Well ranking

(2) For the purposes of subsection (1), the operator must rank a well according to its level of risk and ensure that the well ranking is confirmed by an independent person.

Verification requirements

(3) The verification scheme must set out the verification requirements that are applicable to the design of a well according to the well's ranking and to any changes made to the design during the well's construction or operation that would affect any previously undertaken verification.

Verification by independent person

(4) The operator must ensure that the required verifications are carried out by an independent person that was not involved in the original design.

General

- This applies to the well integrity life cycle of each well from design, through drilling and construction, operation and maintenance, production, any well intervention activities up to its final plugging and abandonment, and it applies to any wells that have been suspended.
- Operators are required to rank a well according to its level of risk. This well ranking will determine the level of verification. It is interpreted that wells such as deepwater wells, HPHT wells, wells expected to contain H_2S, or any other well in which there may be increased concern regarding the safety of persons or protection of the environment will be considered high risk and should warrant more in-depth verification. The independent person referred to in subsection 19(4) of the *Framework Regulations* is referred to in this guidance as the “well verifier”.
- The following documents should be considered when developing and implementing a well verification scheme for all phases of the well integrity life cycle:
  - *NORSOK D-010 Well integrity in drilling and well operations*
  - *Norwegian Oil and Gas Association Recommended Guidelines for Well Integrity – No. 117*

Well Verification Scheme

- The operator is responsible for the development of a well verification scheme that covers the well integrity aspects of all existing and future wells. The scheme should be a stand-alone process or document, but may reference existing processes and documents. Each operator is responsible for ensuring that the scheme is in place, the well verifier is both competent and independent, and the scheme is and continues to be effective for the life cycle of the well. Recommendations from the well verifier should be considered and suitable action taken where required.
- The well verification scheme should include the following:
  - Identification of the well integrity risks for the lifecycle of the well.
  - Description of roles and responsibilities for all persons responsible for the scheme.
  - A review of the subsurface environment, including the geological strata, the fluids within them, formation pressures and any hazards that the strata may contain.
  - A review of the design, construction, operations and maintenance of the well including the well integrity parameters to be monitored for the life of the well.
  - A review of any planned well intervention activities and the eventual plugging and abandonment.
  - A review of the barriers, equipment, procedures and any other matters that could affect the integrity of the well.
  - A review of the competency and independence of the well verifier. Existing company competency assessment processes may be used.

- Criteria for re-engagement of the well verifier if there is a change in the well verification scheme, a modification to the well or associated equipment, proposals to operate the well with impairments, proposals for long-term shut-in without monitoring and testing, changes to procedures or personnel or any other change that can have an impact on well integrity.

Well Verifier

- More than one well verifier (i.e., a verification team) may be used for any review.
- The well verifier(s) should have technical knowledge, qualifications and experience of the work being undertaken that covers the full life cycle of the well from design to final abandonment and any operation that may be performed on the well or any changes that could occur (e.g., degradation of barriers, change in well fluids or change in reservoir) over the lifetime of the well.
- Although it is permissible for the well verifier(s) to be an employee of the operator, they should be in a separate department or business unit (i.e., does not report directly to persons that are accountable for the well design and operation) that was not involved in the original design or execution of the well operation program.
- The well verifier(s) should be provided with all information necessary to complete a thorough review.
- The operator should provide, in writing, a list of the independent well verifiers to the *Regulator*, including their position title, qualifications and proof of independence. The *Regulator* should be notified, in writing, of any changes to the well verifier list.

Reports

When a well design is assessed as part of the well verification scheme by a well, a report should be produced and filed internally that includes:

- the name and signature of the well verifier(s) and their associated competency;
- an assessment of all risks and identified measures;
- a review of the well design;
- a review of the equipment;
- a review of the well operations;
- a review of the training and competency of persons involved in well operations; and
- any remedial actions or recommendations resulting from the review.

The ADW template includes a section on the well verification scheme. It requests the operator to confirm the well ranking and to confirm that all well requirements regarding design and planned execution have been met. Additionally, the operator is requested to describe any risk prevention, mitigation or other actions identified by the well verifier and to reference the associated document number and date of the verification report.

Existing Wells

Existing wells, either active or suspended, should be subject to a well verification scheme assessment as part of an established well integrity management system. The well ranking of existing wells should consider the current condition of all well barriers and the current status of the well. A summary of the verification of well integrity should be included in the annual production report referred to in section 202 of the *Framework Regulations*. Wells which have been subject to a verification as part of ongoing well operations (e.g., workover, intervention) are exempt from the well verification scheme for a period of one year from the end of the operation.

Sections 20 – 22 - Suspension or Revocation of a Well Approval

Suspension of well approval

20 (1) The Board may suspend a well approval if
(a) the operator conducts the well operation other than as described in the application for the well approval;
(b) the physical and environmental conditions encountered in the area of the work or activity for which the well approval was granted are more severe than those on the basis of which the manufacturer of any equipment used in the well operation established the equipment's operating limits; or
(c) the operator uses a flow system, flow calculation procedure or flow allocation procedure that has not been approved under subsection 14(2), conducts a formation flow test that has not been approved under subsection 63(5) or engages in commingled production that has not been approved under subsection 80(2).

Factors for Suspension

(2) In deciding whether to suspend an approval, the Board must consider:
(a) the effects or potential effects of the applicable situation referred to in subsection (1) on safety, the environment and the conservation of petroleum resources; and
(b) the operator's history of non-compliance with the requirements of these Regulations, the provisions of Part III of the Act or any requirements that are established by the Board under that Part with respect to well operations.

Revocation of Well Approval

21 The Board must revoke a well approval if
(a) the operator fails to remedy the situation that caused the suspension of the well approval as soon as the circumstances permit within 60 days after the date of that suspension unless, on written request by the operator, the Board grants the operator an extension of time to remedy the situation; or

(b) the operator continues to operate the well despite the suspension of the well approval.

Suspension or abandonment of well

22 If a well approval is revoked, the operator must ensure that the well is suspended or abandoned in accordance with Part 8.

With respect to paragraph 20(1)(b) of the *Framework Regulations*, refer to the requirements and associated guidance on physical and environmental conditions and the associated forecasting, observation and reporting in sections 42, 104, 106 and 109 of the *Framework Regulations.*

DEVELOPMENT PLAN

Section 23 - Development Plans

Well Approval - Subsection 139(1) (or 143(1)) of the Act

23 For the purposes of subsection 139(1) (or 143(1)) of the Act, a well approval relating to a production project is prescribed.

No guidance required at this time.

Section 24 – Concept Safety Analysis

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24 (1) The approvals referred to in subsection 139(4) (or 143(4)) of the Act are subject to the operator's submission of a concept safety analysis to the Chief Safety Officer at the time the operator submits the application and proposed development plan to the Board under subsection 139(2) (or 143(2)) of the Act.

Content

(2) The concept safety analysis must
(a) be based on the development concept chosen by the operator as a general approach and described in Part I of the development plan;
(b) take into account all works and activities associated with each phase in the life cycle of the development;
(c) determine target levels of safety that are to be achieved to ensure safety and the protection of the environment for all works and activities within each phase of the life cycle of an

installation, including its systems and equipment, from the installation's design up to and including its decommissioning and abandonment;
(d) identify all hazards having the potential to cause a major accidental event;
(e) include a systematic assessment of the unmitigated risks associated with each of the identified hazards, including the likelihood of a major accidental event occurring and the consequences that would result;
(f) identify the control measures that are to be implemented to reduce the risks associated with the identified hazards to a level that is as low as reasonably practicable;
(g) identify the effects of any additional risks that may result from the implementation of the identified control measures; and
(h) identify all assumptions on which any aspect of the concept safety analysis is based.

Quantitative and qualitative risk assessments

(3) The target levels of safety must be based on risk assessments that are
(a) quantitative, if it can be demonstrated that input data are available in the quantity and quality necessary to demonstrate the reliability of the results; or
(b) qualitative, if the criteria in paragraph (a) are not met or if a quantitative assessment would otherwise be inappropriate.

Contents of risk assessment

(4) The operator must include in the risk assessment a description of the circumstances that will necessitate an update of the risk assessment, including changes in
(a) the physical and environmental conditions;
(b) the operating conditions and the limits taken into account in the design assumptions; and
(c) the operating procedures.

Review of risk assessment

(5) The operator must update the risk assessment as often as necessary and at least once every five years throughout the life cycle of the development to
(a) account for the circumstances described in subsection (4); and
(b) ensure the ongoing suitability of the control measures to maintain risks at a level as low as reasonably practicable.

General

- With respect to this section, particular reference should be made to the definitions of "major accidental event" and "safety-critical element" in section 1 of the *Framework Regulations*. It should be noted that the term "safety-critical element" refers both to equipment that is critical to safety and critical for preventing pollution.

- Refer to the requirements and associated guidance under Part 3 of the *Framework Regulations* and Part 2 of the *OHS Regulations*.
- Refer to the requirements and associated guidance under section 108 of the *Framework Regulations* which deals mainly with major accidental events and as such, are directly linked to the development of performance standards for safety-critical elements under section 159 of the *Framework Regulations*.
- With respect to subsections 24(4) and (5) of the *Framework Regulations*, it is recognized that most operators have not maintained and updated the concept safety analysis, but have incorporated the target levels of safety, assumptions and measures from the concept safety analysis into the ongoing quantitative and qualitative risk assessments for the installation. If this is the case, subsections 24(4) and (5) of the *Framework Regulations* apply to the ongoing quantitative and qualitative risk assessments.
- Refer to section 108 of the *Framework Regulations* for a full suite of referenced documents that should be considered for the conduct of the concept safety analysis.
- As much as is reasonably practicable, the operator should engage persons who will be employed during the operation and maintenance of the project in risk assessments and associated studies.
- Refer to the *Development Plan Guideline* for additional information on the concept safety analysis.
- The operator should ensure that any assumptions, measures and target levels of safety are included in documentation submitted in support of an application for an OA submitted to the *Regulator*.

Scope of Concept Safety Analysis

The scope of the concept safety analysis should address all activities associated with each phase in the life cycle of the development. It should consider all hazards and risks associated with any activity that may be conducted in relation to the development of the field. This includes any associated transportation, diving, construction, development drilling, geoscientific, geotechnical or environmental activities, as well as, any associated logistical support provided. This should also include associated hazards and risks with ongoing construction, installation and maintenance activities and extend out to its eventual decommissioning and abandonment. Changes in physical and environmental conditions over the life cycle of the development should also be assessed for impacts.

The concept safety analysis should include the assessment of each type of concept that is being considered for the installation and its associated equipment, and provide rationale for why the selected concept will reduce the risk to ALARP. Any assumptions should carry through to the final design.

Target Levels of Safety

- As there are different approaches to the selection of the target levels of safety, these have not been prescriptively defined in either the *Framework Regulations* or this Guideline. Target levels of safety may be qualitative (e.g., provisions are made for all persons to evacuate) or quantitative (e.g., 1×10^{-6}). A number of requirements have been prescribed by the legislation listed in section 108 of the *Framework Regulations*. In addition, an operator's management system may have more stringent requirements that should be considered.
- The selected target levels of safety should consider factors such as the complexity of the project, level of innovation, level of inherent safety, underlying assumptions, data sources, layers of protection and level of uncertainty. Quantitative targets may also vary depending on the type of major accidental event. The onus is on the operator to apply appropriate practices in determining the target levels of safety and to outline the rationale for the selected levels.
- The target levels of safety in the concept safety analysis should be consistently applied and reflected in all documentation submitted in respect of the *Development Plan,* and should be consistent with the likelihoods for the same events expressed in the associated Environmental Assessments and Impact Assessment and associated studies. They should be carried forward into the front end engineering design, the detailed design and associated risk assessments and studies.
- Although the target levels of safety are established at the concept stage, this is the minimum level to be achieved. The operator should continue its efforts and improve its management system to further reduce the risks.

Section 25 – Resource Management Plan

Resource management plan — paragraph 139(3)(b) (or 143(3)(b)) of the Act

25 (1) For the purposes of paragraph 139(3)(b) (or 143(3)(b)) of the Act, Part II of the development plan must contain a resource management plan.

Contents of resource management plan

(2) The resource management plan must include a description and analysis of the following:
(a) the geological setting and features of the field and of each pool or petroleum-bearing reservoir;
(b) the petrophysical data and analytical procedures for each pool;
(c) the reservoir engineering data for each pool;
(d) estimates of in-place resources and recoverable reserves for each pool, fault block and reservoir subdivision;
(e) the proposed reservoir exploitation scheme;

(f) potential developments and the reasons why they are not included in the proposed development of the field or pool;
(g) any past drilling in the area related to the proposed development of the field or pool as well as the proposed drilling program and typical completion designs for the development wells;
(h) the production and export systems related to the proposed development of the field or pool;
(i) the expected overall operating efficiency and reliability of the proposed development of the field or pool; and
(j) past expenditures and predicted capital and operating cost data, with sufficient detail to permit an economic analysis of the proposed development of the field or pool.

Organizational structure

(3) The resource management plan must also contain a description of the operator's organizational structure as it relates to the implementation of the plan.

- Updates to the Resource Management Plan should be included in the annual production report or more frequently, if requested by the *Regulator*. Refer to the requirements and associated guidance under section 202 of the *Framework Regulations*.
- Refer also to the requirements respecting implementation of the Resource Management Plan under section 50 of the *Framework Regulations*.
- In NL, refer to the guidance on the content of resource management plans in the *Development Plan Guideline*.
- In NS, contact the CNSOPB for guidance on the content of resource management plans.

PART 5: CERTIFICATE OF FITNESS

Sections 26 – 27 - Prescribed Installations

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26 For the purpose of section 139.2 (or 143.2) of the Act, a production installation, drilling installation, accommodations installation and diving installation are prescribed installations.

27 In this Part, installation means an installation referred to in section 26.

The types of installations and vessels required to have a COF issued by a CA includes the following:

- Production Installations, including both subsea and surface systems, including flowlines, umbilicals, pumping stations, onshore control centres, pipelines, etc. (attended or unattended) related to:

- Fixed production installations
- Floating production installations (e.g., FPSOs, FSOs, TLPs, Spar)

- Drilling Installations, including:
  - Fixed drilling installations
  - Ship- shaped MODUs (e.g., drill ships)
  - Column-stabilized MODUs (i.e., semi-submersible drill rigs)
  - Self-elevating MODUs (i.e., jack-up drill rigs)
  - Well intervention vessels (e.g., light intervention vessels)
- Accommodations Installations
- Any vessel or installation engaged in diving operations, and associated light dive craft.

Refer to the definition of “accommodations installation”, “diving installation”, “drilling installation”, “pipeline”, “production installation” and ancillary definitions (e.g., drilling unit, drilling rig, well operations, marine activities, floating platform, mobile offshore platform) in section 1 of the *Framework Regulations*.

Section 28 – Certificate of Fitness

Issuance of certificate — requirements and conditions

28 (1) Before a certifying authority issues a certificate of fitness in respect of an installation,
(a) the person that applies for the certificate must

> ***(i) provide the certifying authority with all the information that the certifying authority requires in relation to the application for certification, such as design specifications for the installation, including its systems and equipment,***
> ***(ii) conduct or assist the certifying authority in conducting any inspection, test or survey that the certifying authority requires,***
> ***(iii) except in the case of a diving installation, submit to the certifying authority for approval a maintenance program that meets the requirements set out in section 159 and a weight control program that meets the requirements set out in section 161, and***
> ***(iv) in the case of a diving installation, submit a maintenance program to the certifying authority for approval;***

(b) the certifying authority must determine that, in relation to the production site, the drill site or the region in which the particular installation is to be operated,

> ***(i) the installation, including its systems and equipment, is fit for the purposes for which it is to be used and can be operated without posing a threat to persons or the environment,***
> ***(ii) in the case of an installation other than a diving installation, the requirements set out in the following provisions have been met:***
>
> > ***(A) the provisions of these Regulations listed in Part 1 of Schedule 1, and***
> > ***(B) the provisions of the Canada–Newfoundland and Labrador Offshore Area Occupational Health and Safety Regulations (or Canada-Nova Scotia Offshore***

Area Occupational Health and Safety Regulations) listed in Part 2 of Schedule 1, other than paragraph 22(5)(b), subsection 28(3), paragraph 28(5)(a), subsection 171(3) and paragraphs 172(1)(a), (g), (j) to (m), (o) and (p), (2)(e) and (3)(c) and (f) of those Regulations,

(iii) in the case of a diving installation, the requirements set out in the following provisions have been met:

(A) section 174 and the provisions of Part 9, and

(B) the provisions of the Canada–Newfoundland and Labrador Offshore Area Occupational Health and Safety Regulations (or Canada-Nova Scotia Offshore Area Occupational Health and Safety Regulations) listed in Part 2 of Schedule 1, and

(iv) the installation, including its systems and equipment, will continue to meet the requirements set out in subparagraph (i) and the applicable requirements set out in subparagraph (ii) or (iii), as the case may be, for the time set out in the certificate of fitness if

(A) the installation - other than a diving installation - including its systems and equipment, is inspected, monitored, tested and maintained in accordance with the maintenance program and is maintained in accordance with the weight control program referred to in subparagraph (a)(iii), or

(B) the diving installation, including its systems and equipment, is maintained in accordance with the maintenance program referred to in subparagraph (a)(iv);

(c) the certifying authority must:

(i) in the case of an installation other than a diving installation, determine that the maintenance program and the weight control program are adequate to ensure the continued integrity of the installation, including its systems and equipment, and approve them; and

(ii) in the case of a diving installation, determine that the maintenance program is adequate to ensure the continued integrity of the installation, including its systems and equipment, and approve it; and

(d) the certifying authority must carry out the scope of work in respect of which the certificate of fitness is issued.

Substitution - Section 151 (or 155) and subsection 205.069(1) (or 210.07(1)) of the Act

(2) For the purposes of subparagraphs (1)(b)(ii) and (iii), the certifying authority may substitute, for any equipment, methods, measures, standards or other things required under any regulation referred to in those subparagraphs, any other equipment, methods, measures, standards or other things the use of which is authorized by the Chief Safety Officer or the Chief Conservation Officer, as the case may be, under section 151 (or 155) or subsection 205.069(1) (or 210.07(1)) of the Act.

Limitations

(3) The certifying authority must set out in any certificate of fitness that it issues the details of any limitation on the operation of the installation that is necessary to ensure that the installation, including its systems and equipment, meets the requirements set out in paragraph (1)(b).

Certificate of Fitness

- Refer to the requirements of the *Accord Acts*[20] for the COF issued by a CA. Additional notes on the requirements of the *Accord Acts* are as follows:
  - While conducting work or activity under an authorization, both the COF applicant and the operator are responsible for ensuring the COF issued by the CA remains valid.
  - A limitation on a COF is a technical assessment by the CA but it should not be assumed to provide automatic temporary exemption from a regulation. Any proposed exemption from a regulation (e.g., RQ), temporary or otherwise, must be provided to the *Regulator* separately.
- With respect to an installation, a COF is expected to be issued prior to the first major part/component(s) of the installation being transported and installed on the drill site or production site. It is expected that any systems (e.g., temporary or permanent marine, life-saving, firefighting systems) that are required for the initial installation, hookup and commissioning are also reviewed by the CA as part of the COF. Refer to requirements and associated guidance under section 121 of the *Framework Regulations*.
- If an installation has been classed by a classification society that is not the CA, it is expected that the CA will assess the work and undertake any additional review or testing that they require to issue a COF.
- In addition to any standard conditions or limitations that may be imposed by the CA, a COF that is issued for an installation not covered under an authorization should identify limitations for any matters required to be addressed prior to commencing operations in the *Offshore Area* under the COF. In these circumstances, the following should be considered:
  - With respect to subsection 28(3) and section 33 of the *Framework Regulations*, the COF should include site specific limitations of the installation.
  - Any equipment or systems yet to be assessed (e.g., third party equipment) should be specified.
  - Compliance to all other requirements of the regulations which form part of the COF and under the remit of the CA prior to start of operations within the *Offshore Area* must be demonstrated. This compliance should also be clear within any related limitation.
- When an installation ceases to operate under an authorization but continues to maintain a COF, appropriate limitations should be added to the COF to reflect the need for verification before resuming activities in the *Offshore Area*.
- Refer to requirements of sections 32 and 33 of the *Framework Regulations* for the period of validity and applicable site or region on the COF.

[20] C-NLAAIA 139.2(1), (2), (3), (4); CNSOPRAIA 143.2(1), (2), (3), (4)

- For the purposes of issuing the COF, the *Regulator* has prescribed the *Certificate of Fitness* form. This form is available on the *Regulator's* websites.

Equivalent Standards and Exemptions

With respect to subsection 28(2) of the *Framework Regulations*, refer to the following:

- The CA should be engaged on equivalent standards and exemptions for requirements that are under the remit of the CA.
- Supporting rationale/justification of the CA's review and concurrence may be required (e.g., submission of comment response sheets, acceptance letter).
- The concurrence from the CA should be accompanied by any approval or exemption documentation from flag state and classification society (if different from the CA), as applicable.
- Additional guidance is provided in section 2.3 of this Guideline.

Limitations

With respect to subsection 28(3) of the *Framework Regulations*, refer to the following:

- A "limitation" is interpreted to mean any restriction placed by the CA in relation to requirements covered by the COF (e.g., depending on the CA this could be a limitation, qualification, condition of authority). This should be linked to a direct regulatory requirement or other requirement of the *Regulator*.
- Some examples of the different types of limitations that could be included on a COF:
    - General, site specific or field specific limitations.
    - Limitations regarding long-term or short-term operation of the installation (e.g., physical and environmental conditions operating limitations).
    - Limitations for those events that must take place for a COF to remain valid.
    - Limitations respecting operation of equipment, systems or the installation (e.g., equipment operating limitations, non-compliant component/equipment, systems that are not fully commissioned, modifications to systems, systems with changed status).
    - Conditions of class from any classification society requirements related to requirements covered by the COF.
    - Conditions of authority or qualifications from any flag state requirements related to requirements covered by the COF.
- The process for adding, modifying and deleting limitations on the COF should be included in the scope of work referenced in section 31 of the *Framework Regulations*. Formal communication on any changes to the limitations should be submitted to the *Regulator* at the same time they are issued to the COF applicant. The CA should also coordinate with the installation owner how the operator will be kept apprised of any limitations and changes to the COF as it would impact the operator's authorization.
- Limitations in respect to the COF may also be matters related to flag state and class. Regardless of the mechanisms for tracking flag state and class related matters, if these are also in relation

to requirements covered by the COF, they should be clearly identified as limitations associated with the COF.

- The operator must operate the installation in accordance with any limitations set out in the COF as referred to in section 156 of the *Framework Regulations*.

Section 29 – Conflict of Interest – paragraph 139.2(4)(b) (or 143.2(4)) of Act

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29 (1) For the purposes of paragraph 139.2(4)(b) (or 143.2(4)(b)) of the Act, the extent to which a certifying authority may participate in the design, construction or installation of an installation in respect of which a certificate is issued is as follows:
(a) the certifying authority or one of its subsidiaries or affiliates may be the certifying authority or classification society for the original design, construction or installation of the installation or any modification to it; and
(b) a subsidiary or affiliate of the certifying authority may participate in the design, construction or installation of the installation to any other extent as long as it does not participate in any of the certification or verification activities in respect of the installation.

Notice of non-compliance
(2) The certifying authority must monitor for any participation beyond that described in subsection (1) and must, without delay, inform the person that applied for the certificate and the Board of any such participation.

- While this section of the regulations uses the terms “CA”, “classification society”, “subsidiary or affiliate”, pursuant to the *Accord Acts*, this also applies to any “person or organization.”
- While this section of the regulations uses the term “installation”, pursuant to the *Accord Acts*, this also applies also to any equipment.
- With respect to paragraph 29(1)(b) of the *Framework Regulations*, a subsidiary or affiliate of the CA may participate in the design, construction or installation of the installation provided the CA:
    - maintains appropriate segregation of management lines between any work being undertaken by the CA on the design, construction or installation of the installation;
    - ensures that no person or organization that has carried out the work to be certified or verified takes part in the certification or verification activities;
    - ensures appropriate barriers and processes are in place to deal with potential or perceived conflicts of interest that could bias their ability to independently verify compliance with the regulatory requirements and to otherwise execute their responsibilities as a CA; and
    - demonstrates this independence and impartiality, and identifies any possible or perceived conflicts in the Scope of Work referred to in section 31 of the *Framework Regulations*.

Section 30 – Certification Plan

30 (1) A person that applies for a certificate of fitness must submit a certification plan to the Chief Safety Officer and to the certifying authority for the purposes of the approval of the scope of work under section 31.

Contents

(2) The certification plan must include the following documents and information:
(a) a description of the installation that is to be certified, including its systems and equipment;
(b) a list of the standards that will apply to the installation to be certified, including its systems and equipment, and a list of the standards on which the measures to reduce risks that are described in the safety plan and the environmental protection plan are based or, if there are no applicable standards, any studies and analyses that demonstrate that the measures to be implemented are adequate to reduce the risks to safety and the environment to a level that is as low as reasonably practicable or to minimize the risk of hazards, as the case may be; and
(c) other than in the case of a diving installation, a list of all safety-critical elements, as well as a description of how the associated performance standards are to be developed.

General

- The Certification Plan is developed by the applicant for a COF and must identify the codes and standards, or in the case where there are no codes and standards, list any studies and analyses carried out that demonstrate adequate risk reduction measures pertaining to the design, construction and maintenance are applied. The technologies and methods identified by the applicant to be used in the design, construction and maintenance of the installation forms the foundation of the Certification Plan, as required under Part 5 of the *Framework Regulations*.
- The Certification Plan is intended to be a tool used for establishing CA verification for the installation, and specific systems and equipment that fall under the CA's remit.
- The applicant is responsible to have the Certification Plan reviewed and endorsed by the CA prior to submitting it to the *Regulator*. It is not the CA's role to develop the Certification Plan.
- The Certification Plan may be developed using references to existing documents submitted in support of an application for an OA or other approval including the Safety Plan(s), Environmental Protection Plan(s), Contingency Plan(s), concept safety analysis, etc., and they may also be supplemented with other documents such as design documents, performance standards, etc. When the Certification Plan references other documents, it is the applicants responsibility to:
    - clearly identify the aspects of the existing documents that will form the basis of the Certification Plan through specific references;
    - ensure it clearly identifies the codes, standards and measures being applied, as applicable; and

  - ensure those aspects are included or added to the CA's review scope.
- Once a Certification Plan has been developed by the applicant, the CA should review and provide comments to the applicant and when satisfied, endorse the Certification Plan.
- For new build installations, the Certification Plan should be submitted after approval of the *Development Plan* and at or near the completion of the front end engineering design (i.e., FEED) stage. It is understood that there will still be information to be finalized during detailed design, and as such, a subsequent iteration of the Certification Plan may be submitted at the detailed design stage.
- The Certification Plan should be reflective of the works or activities being undertaken onboard the installation and should be updated to reflect any changes. Revisions to documentation that forms the basis of the Certification Plan should be submitted for review and endorsement by the CA and CSO before implementation. No changes should be made to other documents referenced within the Certification Plan without the endorsement of the CA.
- In NL, refer to the *Guideline for Petroleum – Related Authorizations and Approvals* for timelines and submissions of certification plans based on the type of installation in use. In NS, contact the CNSOPB for guidance on other requirements for OAs.

Description of Installation

With respect to paragraph 30(2)(a) of the *Framework Regulations*, the Certification Plan must include a description of the installation and associated systems and equipment to be verified by the CA. This should include a description of the physical bounds of the items covered as part of the COF as not all equipment is under the remit of the CA.

List of Codes, Standards and Measures

With respect to paragraph 30(2)(b) of the *Framework Regulations*, refer to the following:

- There are several acceptable means to meet the requirements and this may differ depending on the installation type, the type of works or activities being conducted, the hazards and risks associated with those works or activities and the management system.
- If there are no codes or standards identified, the Certification Plan should list any studies and analyses carried out which demonstrate that adequate risk reduction measures pertaining to the design, construction and maintenance are applied. It is noted that this may already be included within existing documentation submitted to the *Regulator* and rather than repeat this information it is possible to reference these documents as necessary.
- The implementation of the codes, standards, studies or anlaysis as described in the Certification Plan should be reviewed and subsequently verified by the CA.
- The applicant should also identify which parts of the code or standard are being applied otherwise it is assumed that the entire code or standard is being applied, including normative references to other codes or standards. A code or standard that is a normative reference in another code or standard does not need to be listed in the Certification Plan.
- The applicant should include commentary on how the inspection, testing and maintenance requirements from codes and standards are captured and managed within their maintenance

system and related performance standards. This should include commentary pertaining to the CA approval process.

- Guidance on the codes, standards and other considerations is provided in the relevant applicable sections of the guidelines for the *Framework Regulations* and the *OHS Regulations*. The tables below contain topics to be included in the Certification Plan, as applicable, to the specific type of installation. High-level regulatory references are included within the table for guidance; however, the applicable clauses under the CA's remit are further prescribed in Schedules 1 and 2 of the *Framework Regulations.* The Certification Plan may also include any major equipment or system covered under the bounds of the COF unique to the installation type or planned operations*.*

Production, Drilling and Accommodations Installations

Quality Assurance [*Framework Regulations* 100]	Design for Intended Use and Location (including design for removal) [*Framework Regulations* 98, 104, 105]
Passive Fire And Blast Protection [*Framework Regulations* 112]	Hazardous and Non-Hazardous Areas [*Framework Regulations* 113; *OHS Regulations* 26]
Ventilation Systems [*Framework Regulations* 114; *OHS Regulations* 57, 78, 79]	Ignition Prevention [*Framework Regulations* 115]
Means of Escape, Evacuation and Rescue [*Framework Regulations* 116]	Temporary Safe Refuge [*Framework Regulations* 117]
Exits, Access and Escape Routes [*Framework Regulations* 118]	Life-Saving Appliances [*Framework Regulations* R 119]
Electrical Systems (including Emergency) [*Framework Regulations* 122, 126; *OHS Regulations* 24, 74, 144]	Control and Monitoring Systems and Software [*Framework Regulations* 123, 124, 125, 169]
Lights and Sound-Signalling Appliances [*Framework Regulations* 127]	Radar [*Framework Regulations* 128]
Communication System [*Framework Regulations* 129; *OHS Regulations* 23]	General Alarm System [*Framework Regulations* 130; *OHS Regulations* 23]
Gas Release Systems [*Framework Regulations* 131]	Fire and Gas Detection System [*Framework Regulations* 132]
Emergency Shutdown System [*Framework Regulations* 133]	Fire Protection Systems and Equipment [*Framework Regulations* 134; *OHS Regulations* 27]
Boilers and Pressure Systems [*Framework Regulations* 135]	Mechanical Equipment [*Framework Regulations* 136]
Materials Handling Equipment [*Framework Regulations* 137; *OHS Regulations* 121, 122, 125]	Temporary or Portable Equipment [*Framework Regulations* 139]
Air Gap [*Framework Regulations* 141]	Stability [*Framework Regulations* 142]
Self-Elevating [*Framework Regulations* 143]	Ballast and Bilge Systems [*Framework Regulations* 144]

Watertight and Weathertight Integrity [*Framework Regulations* 145]	Station Keeping Systems [*Framework Regulations* 146]
Mooring System [*Framework Regulations* 147]	Disconnectable Mooring System [*Framework Regulations* 148]
Dynamic Positioning System [*Framework Regulations* 149]	Dynamic Positioning Disconnect System [*Framework Regulations* 150]
Corrosion Management [*Framework Regulations* 155]	Landing Area [*Framework Regulations* 174]
Elevators and Personnel Lifts [*OHS Regulations* 93]	Elevating Work Platforms [*OHS Regulations* 107]

Production-Related

Subsea Production Systems [*Framework Regulations* 138]	Pipelines [*Framework Regulations* 168]

Well Operations-Related

Well Control (including pressure control equipment) [*Framework Regulations* 68]	Drilling Fluid Systems [*Framework Regulations* 163]
Drilling Riser [*Framework Regulations* 164]	Fail-Safe Subsurface Safety Valves [*Framework Regulations* 165]
Well Tubulars, Trees and Wellheads [*Framework Regulations* 166]	Formation Flow Test Equipment [*Framework Regulations* 167]

- For diving installations, the Certification Plan should include the requirements of Part 9 and section 174 of the *Framework Regulations* and the *OHS Regulations*.

Diving Installations (for the purposes of issuing a COF)

Design of Vessel [*Framework Regulations* 94]	Ventilation Systems [*OHS Regulations* 57, 78, 79]
Electrical Systems (including Emergency) [*OHS Regulations* 24, 74, 144]	Communication System [*OHS Regulations* 23, 171(3)]
General Alarm System [*OHS Regulations* 23]	Fire Protection Systems and Equipment [*OHS Regulations* 27]
Materials Handling Equipment [*OHS Regulations* 121, 122, 125]	Elevators and Personnel Lifts [*OHS Regulations* 93]
Elevating Work Platforms [*OHS Regulations* 107]	Dynamic Positioning Systems [*Framework Regulations* 95]
Diving Systems (including launch and recovery system, breathing mixtures, compression chambers, dive bells, hyperbaric evacuations system, etc.) [*OHS Regulations* 172]	Light Dive Craft [*Framework Regulations* 96]
Landing Area [*Framework Regulations* 174]	

List of Safety Critical Elements and Performance Standards

With respect to paragraph 30(2)(c) of the *Framework Regulations*, the Certification Plan for production, drilling or accommodations installations (excludes diving installations) refer to the following:

- The requirements and associated guidance for how safety critical elements are determined in section 108 of the *Framework Regulations*.
- The requirements and associated guidance on performance standards in section 159 of the *Framework Regulations*.

Section 31 – Scope of Work

31 (1) A certifying authority must submit to the Chief Safety Officer for approval a scope of work that takes into account the certification plan.

Contents of scope of work

(2) The scope of work must include
(a) a description of the following activities to be conducted by the certifying authority:
(i) activities to verify compliance with the requirements set out in paragraph 28(1)(b),
(ii) activities to verify the validity of the certificate of fitness, and
(iii) any additional activities to be carried out before the renewal of the certificate; and
(b) a schedule of the activities referred to in paragraph (a).

Approval of scope of the work

(3) The Chief Safety Officer must approve the scope of work if the Chief Safety Officer determines that
(a) in the case of any installation, the scope of work
(i) is sufficiently detailed to permit the certifying authority to determine whether the requirements set out in paragraph 28(1)(b) are met,
(ii) describes the type and extent of reporting in respect of continual monitoring of the certification process being undertaken by the certifying authority, and
(iii) demonstrates how the certifying authority has complied with section 29;
(b) in the case of an installation other than a diving installation, the scope of work
(i) provides the means for determining whether
(A) the environmental criteria for the region or site and the loads estimated for the installation are correct,
(B) the list of safety-critical elements included in the certification plan is complete and the elements are in place and functioning as intended,

(C) in respect of any installation referred to in a development plan, the concept safety analysis submitted under section 24 meets the requirements set out in that section,
(D) in respect of a new installation, the installation has been constructed in accordance with the quality assurance program referred to in section 100,
(E) the operations manual meets the requirements set out in section 157, and
(F) the installation's construction and installation, including the materials used for those purposes, meet the design specifications,
(ii) includes the list of performance standards and methods that the certifying authority will use to verify compliance with those standards and to verify whether the installation, including its systems and equipment, continues to be fit for the purposes for which it is to be used, and
(iii) provides the means for determining whether the provisions listed in Schedule 2 have been complied with and whether the structures, systems and equipment referred to in those provisions are in place and functioning as intended; and
(c) in the case of a diving installation, the scope of work provides the means for determining whether the processes referred to in subparagraph 4(1)(m)(iii) and paragraph 4(1)(v) that are included in the operator's management system have been implemented.

The Scope of Work should be submitted for review and approval before the CA conducts verification activities. For installations in the *Offshore Area* on a short-term basis and for diving vessels, this should be submitted no later than six months before issuance of an authorization. The Certification Plan should either accompany the submitted Scope of Work as an appendix or be appropriately referenced within the Scope of Work document.

Contents

The Scope of Work should include the following:

- All activities associated with the life cycle of the project.
- References to all applicable requirements of the regulations the CA will verify.
- With respect to new-build installations, an outline of the processes for design verification and for assessing the quality management system(s) during construction.
- With respect to section 29 of the *Framework Regulations*, a high level commitment that conflict of interest was/will not be an issue, and describe the processes the CA has in place to achieve independence and impartiality, in particular, in the event of a perceived or actual conflict of interest. The CA's organizational structure that provides appropriate segregation of line management should also be included.
- It should outline the process for developing, implementing and revising CA verification elements of performance standards and should describe how the CA will conduct verification activity for each of these elements. This should include a combination of review activities, such as certification, physical inspection and witness performance testing. All systems should contain some level of verification activity conducted by the CA. In addition, the Scope of Work should include a description of the process used for assessing the application of remote

verification activities. This includes highlighting the applicable elements of the verification schemes that involve remote verification.
- With respect to subsection 28(2) of the *Framework Regulations*, the process for review and concurrence of regulatory equivalencies or exemptions, relevant to the scope.
- With respect to section 28 of the *Framework Regulations*, commentary of the initial review and approval of the inspection, monitoring, testing and maintenance program and weight control program and a summary of the monitoring activities to verify that the programs remain valid.
- With respect to subsection 31(2) and section 39 of the *Framework Regulations*, the types of ongoing monitoring, review and surveys to be conducted, as well as, the processes for submission of reports and for close-out or update of the status of any observations, nonconformities, limitations or conditions.
- With respect to subsections 162 and 170 of the *Framework Regulations*, describe the process for the CA being notified of and for assessing repairs, replacements, modifications, damage, incidents, etc. related to the relevant installation, vessel or equipment, including temporary or portable equipment.
- A list of any class notations and associated classification society rules to obtain and maintain them, including any limitations and conditions associated with the class notation.
- A list of flag state requirements applicable to maintain the vessel's certification for the vessel type (e.g., tanker, cargo ship) including any limitations and conditions associated with the vessel's certification.
- A description of the CA's internal quality management system including specifics in relation to the following:
  - high level expectations related to competency of surveyors and reference to associated procedures;
  - arrangements in place for carrying out the duties of an "authorized inspector" (if so designated) as defined by section 1 of the *Framework Regulations* for pressure systems, elevators and materials handling equipment, as applicable;
  - if inspections by external third parties are being relied upon by the CA, then the Scope of Work should provide commentary around the CA's acceptance of such persons or entities for that purpose;
  - overall organizational structure of the CA as it relates to certification and how the CA fits into the overall organization structure of the company; and
  - reporting to the Ministers.

Section 32 – Period of Validity

32 (1) A certificate of fitness is valid for five years from the day on which it is issued if the certifying authority determines that the requirements referred to in paragraph 28(1)(b) will be met for a period of at least five years from that day.

Less than five years

(2) If the certifying authority determines that the requirements referred to in paragraph 28(1)(b) can be met only for a period that is less than five years, the certificate of fitness is valid for the corresponding lesser period.

Expiry date

(3) The certifying authority must indicate on the certificate of fitness its expiry date.

Extension of period of validity

(4) The certifying authority may, on request of the holder of a certificate of fitness, extend the period of validity of the certificate of fitness for a period of up to three months, subject to the approval of the Chief Safety Officer.

Approval by the Chief Safety Officer

(5) The Chief Safety Officer must approve the extension of the period of validity of the certificate of fitness if the extension does not compromise safety or the protection of the environment.

No guidance required at this time.

Section 33 – Applicable Site or Region

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33 (1) A certifying authority must indicate on a certificate of fitness the site or region where the installation is to be operated.

Validity

(2) A certificate of fitness is valid for the operation of the installation at the site or in the region that is indicated on the certificate of fitness.

If the work scope being completed by the installation is conducted in several locations, then the COF should include the physical and environmental operating conditions for each location.

Section 34 – Revalidation – Scope of Work

34 (1) The certifying authority must revalidate the scope of work against the criteria referred to in subsection 31(3) and make any modifications that are necessary

(a) before renewing a certificate of fitness; and

(b) if new circumstances such as the following arise that have or could have a significant impact on the scope of work:

(i) these Regulations or the Canada–Newfoundland and Labrador Offshore Area Occupational Health and Safety Regulations (or the Canada–Nova Scotia Offshore Area Occupational Health and Safety Regulations) are amended,

(ii) new information regarding a major accidental event that occurred in any place is disclosed,

(iii) amendments are made to any of the standards on which the certification was based, or

(iv) the installation has transitioned from one life cycle phase to another.

Revalidation approval

(2) The revalidated scope of work must be submitted to the Chief Safety Officer for approval under subsection 31(3).

- With respect to subsection 34(1) of the *Framework Regulations*, any proposed changes to a Scope of Work should be provided for review and approval before any changes occurring. This would include changes to content or change of the installation owner and COF Applicant (if different).
- With respect to subparagraph 34(1)(b)(ii) of the *Framework Regulations*, this includes consideration of major accidental events that occur locally or internationally (e.g., Deepwater Horizon) that may impact measures in relation to design or inspection, testing and maintenance practices.
- With respect to subparagraph 34(1)(d)(iv) of the *Framework Regulations*, this includes the following:
  - An installation operating beyond its original design life.
  - Decommissioning or abandonment of all or part of the installation or any of its associated systems.
  - Reclassification or conversion of an installation from one type to another type.
- With respect to subsection 34(2) of the *Framework Regulations*:
  - Revalidated scopes of work should be submitted at least six months before the expiry of the COF.
  - If there are no changes in the Scope of Work during the renewal period of the COF, then the revalidated Scope of Work should include a statement that no changes have been made from the previous revision.

Section 35 – Renewal of a Certificate

35 The certifying authority must renew the certificate of fitness in relation to an installation before or on its expiry date if
(a) the certifying authority determines that the requirements referred to in paragraph 28(1)(b) have been met;
(b) the certifying authority has carried out the activities referred to in subparagraph 31(2)(a)(iii); and
(c) the certifying authority has revalidated the scope of work and it has been approved by the Chief Safety Officer.

No guidance required at this time.

Section 36 – Invalidity

36 (1) Subject to subsections (2) and (3), a certificate of fitness ceases to be valid if
(a) the certifying authority or the Chief Safety Officer determines that
> ***(i) any of the information provided under subparagraph 28(1)(a)(i) on the basis of which the certificate of fitness was issued is incorrect,***
> ***(ii) any of the requirements referred to in paragraph 28(1)(b) are no longer being met, or***
> ***(iii) any limitation set out on the certificate of fitness under subsection 28(3) has not been respected; or***

(b) the Chief Safety Officer determines that the certifying authority has failed to carry out the scope of work relating to the installation in respect of which the certificate of fitness was issued.

Notice in writing

(2) At least 30 days before a determination referred to in subsection (1) is made, notice of the impending determination must be given in writing
(a) in the case of a determination to be made by the certifying authority, by the certifying authority to the Chief Safety Officer and to the holder of the certificate of fitness; and
(b) in the case of a determination to be made by the Chief Safety Officer, by the Chief Safety Officer to the certifying authority and to the holder of the certificate of fitness.

Consideration of information

(3) Before making a determination referred to in subsection (1), the certifying authority or the Chief Safety Officer, as the case may be, must consider any information in relation to that determination that is submitted by any person notified under subsection (2).

Refer also to the requirements of the *Accord Acts*[21] for specific requirements respecting the validity of the COF issued by a CA.

Section 37 – Change of Certifying Authority

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37 (1) If the person that applies for a certificate of fitness decides to change the certifying authority in relation to an installation before the initial certificate of fitness is issued, the new certifying authority must undertake its own independent verification activities for the purposes of issuing the certificate of fitness.

After issuance of certificate

(2) If the holder of a certificate of fitness decides to change the certifying authority in relation to an installation, the holder must
(a) notify the Chief Safety Officer as soon as the circumstances permit;
(b) develop and submit to the Chief Safety Officer a transition plan outlining all of the activities to be carried out before transitioning from the outgoing to the incoming certifying authority and demonstrating that there will not be any gaps or delays in the carrying out of verification activities or any negative effects on the extent and quality of those activities as a result of the transition from one certifying authority to another; and
(c) ensure that the incoming certifying authority has submitted for approval to the Chief Safety Officer, in accordance with section 31, a new scope of work before commencing transition activities.

Transition plan implementation

(3) The holder of a certificate of fitness must ensure that the transition plan referred to in paragraph (2)(b) is implemented.

One certificate – one authority

(4) There must be no more than one certificate of fitness and certifying authority in relation to an installation at any given time.

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[21] C-NLAAIA 139.2(4); CNSOPRAIA 143.2(4)

Before Initial Certificate

With respect to subsection 37(1) of the *Framework Regulations*, the independent verification activities should include verification of the following:

- design, fabrication, construction, installation, testing and commissioning; and
- any developed inspection, testing and maintenance programs, weight control programs and operations manuals.

In addition:

- any issues identified from the independent verification should be clearly documented and addressed to the satisfaction of the incoming CA; and
- any outstanding actions from the outgoing CA's verification work should be assigned and addressed to the satisfaction of the incoming CA.

After Issuance of Certificate

- With respect to subsection 37(2) of the *Framework Regulations*, the transition plan should include the following:
  - background information;
  - purpose of the transition;
  - scope of the transition plan including defined point of transition;
  - responsibilities of the incoming and outgoing CA;
  - details of the certification process for the installation;
  - key transition activities for each system of the installation;
  - any details related to inspection, maintenance and weight control plans; and
  - any details related to the Certification Plan.
- It is also expected that both the respective incoming and outgoing CA will concur with the transition plan to ensure there are no gaps with respect to the COF.
- While there is no requirement that specifies the timing surrounding a change in CA, the best time to make the change would be after the initial COF has been issued. If for some reason the change is proposed to occur before that, the transition plan should clearly articulate the rationale for the earlier change in the CA and how any related risks are being managed. In addition, if there is any actual or perceived conflict of interest regarding the design with the incoming CA, such conflict must be identified and mitigated in the transition plan. With respect to conflict of interest, refer to section 29 of the *Framework Regulations*.

One Certificate – One Authority

With respect to subsection 37(4) of the *Framework Regulations*, it is preferred to have all associated platforms and subsea infrastructure referred to as the one installation. However, if this is not the case, and each installation has a different CA, there should be clear boundaries and communications established. The operator should ensure that each CA is kept informed of any issues on one installation that may directly or indirectly affect the other installation.

Additional guidance on the transition from one classification society to another is provided in the *IACS Procedure for Transfer of Class.*

Sections 38 - 39 – Certifying Authority and Reports

Organizational structure

38 A certifying authority must, without delay, notify the Board, the Federal Minister and the Provincial Minister of any changes to its organizational structure, including amalgamations and legal name changes.

Reports and Information

39 (1) A certifying authority must submit to the Board, the Federal Minister and the Provincial Minister, not later than March 31 of each year, an annual report that contains
(a) a summary of the certification activities the certifying authority carried out during the previous calendar year as a certifying authority under the Act; and
(b) proof of its technical capabilities and experience as a certifying authority.

Monthly reports

(2) The certifying authority must submit a monthly report to the Board that describes the certification activities it carried out during the previous month as a certifying authority under the Act.

Information and documents to Board

(3) On the Board's request, the certifying authority must submit to the Board any information obtained or documents generated in the course of carrying out its certification and verification activities.

Record retention

(4) The certifying authority must retain records, including technical drawings, for any activity carried out during its certification or verification activities in respect of an installation until the day that is seven years after the day on which the last certificate of fitness issued for that installation expires.

a. Annual Report

- With respect to paragraph 39(1)(a) of the *Framework Regulations*, annual reports should cover the following:
  - all major verification activities conducted during the period, including:
    - any newly built installations under their remit;
    - in service verification/certification;
    - third party equipment verification; and
    - additional activities in relation to pressure systems, elevators and materials handling equipment, if delegated;
  - summary of new, revised or revalidated Scopes of Work approved; and
  - summary of any new COF's issued.
- With respect to paragraph 39(2)(b) of the *Framework Regulations*, annual reports should outline any associated changes from the last annual report, including changes in:
  - local/regional area and technical support offices;
  - organizational structure; and
  - competency requirements of surveyors.

b. Monthly Reports

With respect to subsection 38(2) of the *Framework Regulations*, monthly reports should include the following, as applicable:

- A list of current limitations related to the COF of the installation.
- A summary of any exemptions issued by flag state or the classification society that are regulatory requirements covered by the COF.
- A high level summary of activities completed by the CA during the month, including:
  - all surveys completed in relation to the COF and the associated status of any observations, limitations or conditions;
  - the status of RQs that are under review, accepted or rejected during the month;
  - significant management of change requests (e.g., design appraisals) that have been reviewed and approved by the CA during the month, along with any associated conditions or timelines with decision;
  - significant repairs or replacements that have been reviewed and approved by the CA;
  - all incidents in which the CA has been engaged; and
  - any items that the CA is actively tracking for that installation or vessel.
- A high level summary of activities planned to be completed by the CA during the upcoming period, including any planned survey(s) and high level scope.

c. Information and Documents to Regulator

With respect to subsection 38(3) of the *Framework Regulations*, the Scope of Work should outline reporting requirements to the *Regulator* according to section 31 of the *Framework Regulations*. As part of the Scope of Work, the CA may be requested to notify or submit the following information:

- Notifications of any changes to limitations or conditions of class, as applicable, as well as, any deletions, inclusive of dates.
- Notifications of any assessments of damage, repairs and replacements that are not reported through other means as the CA becomes aware.

The above information may also be requested to be submitted for any installation with a COF that is not under authorization.

PART 6: GENERAL REQUIREMENTS FOR AUTHORIZED WORKS AND ACTIVITIES

Section 40 – Installation Manager

40 For the purposes of section 193.2 (or 198.2) of the Act, every installation is a prescribed installation.

For clarity, an installation is defined in section 1 of the *Framework Regulation*s and this definition does not include a diving installation. An installation manager is also referred to as an OIM.

Section 41 – Safety and Protection of Environment

41 An operator must take all measures necessary to ensure safety and the protection of the environment during any authorized work or activity, including measures to ensure that
(a) the safety of persons at an operations site or on a support craft has priority, at all times, over any work or activity at the operations site or on the support craft;
(b) safe work methods are adopted;
(c) differences in language or other barriers to effective communication do not jeopardize safety or the protection of the environment;
(d) if there is a loss of well control, all other wells at the same installation are shut in until the well that is out of control is secured;
(e) any equipment that is necessary for safety and the protection of the environment is available and in a condition to perform as intended at all times;
(f) fires can be controlled and extinguished and any related hazard to safety or the environment is minimized;
(g) the administrative and logistical support that is provided for any work or activity includes accommodation and transportation and storage and repair facilities that are fit for the purposes for which they are to be used;
(h) every operations site is equipped with a communication system that meets the requirements set out in subsection 129(1);

(i) any operating procedure that creates a hazard to safety or the environment is corrected; and
(j) all affected persons are informed of any correction made under paragraph (i).

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a. Measures

With respect to the measures identified in section 41 of the *Framework Regulations*, it should be noted that the measures provided in paragraphs (a) through (j) is not an exhaustive list. Operators should identify and assess all hazards that can result in major accidental events or that pose a risk to OHS or the environment. Guidance on OHS-related hazards is provided in the *OHS Regulations* and associated guidance. Environmental hazards should include any hazard that can impact the benthic environment. Additional guidance is provided as follows:

- With respect to paragraph 41(a) of the *Framework Regulations*, for support craft, refer also to the requirements and associated guidance under section 171 of the *Framework Regulations*.
- With respect to paragraph 41(b) of the *Framework Regulations*, the work methods developed should be reflective of all OHS and environmental hazards and should be based on the requirements described in the *Accord Acts* and the requirements of the *OHS Regulations* and *Framework Regulations*. It should also consider associated guidance for both these regulations.
- With respect to paragraph 41(c) of the *Framework Regulations*, other obstacles to effective communication should consider noise, the availability and location of communication equipment, the availability of documentation in all languages at the workplace, etc.
- With respect to paragraph 41(e) of the *Framework Regulations*, all equipment required for safety and environmental protection should be interpreted as being all equipment that is required by both the *Framework Regulations* and the *OHS Regulations.* This should also include any additional equipment identified as a measure to reduce risks to ALARP, including any equipment that has been identified as a safety-critical element.
- With respect to paragraph 41(g) of the *Framework Regulations*, administrative and logistical support is interpreted to include all offshore and onshore support arrangements in place such as support craft, medical support, onshore physicians, forecasting and monitoring of physical and environmental conditions, provision of spill response equipment and services, flight or vessel following services, communications, etc. Operators must exercise their own due diligence with respect to any administrative and logistical support arrangements that are in place for the work or activity. As part of the operator's DOF, the activities to demonstrate this should include the following:
    - An assessment of the management system, equipment, procedures and personnel, including associated maintenance systems, as applicable.
    - A review of previous incidents.

For support craft, the review of incidents should not be solely focused on injury statistics and should include a review of any incidents relevant to its capability in performing its scope (e.g., such as incidents relating to its ability to maintain position (e.g., DP, impairments to equipment, loss of towing equipment).

In addition, for support craft that are vessels (e.g., support vessels), sole reliance on the vessel's existing certifications issued by flag state and classification societies is not considered adequate. It is expected that operators will conduct their own verification activities for vessel acceptance (e.g., surveys, audits and inspections) and ensure that any non-compliances or non-conformities are addressed satisfactorily. This is particularly important if the support vessels are not safety convention vessels, have exemptions from flag state, were not designed or operated in similar physical and environmental conditions or do not carry a Certificate of Class by a recognized classification society, as in these cases such vessels may be legally exempt from the application of certain flag and class requirements relevant to design, construction, equipment and crew certification and training.

b. Support Craft

With respect to paragraph 41(g) of the *Framework Regulations*, refer to the definition of support craft in section 1 of the *Framework Regulations.* A support craft also includes the standby vessel as discussed in section 171 of the *Framework Regulations.*

Additional guidance on support craft operations are provided in the following:

- Guidance on standby vessels is provided in the *Standby Vessel Guideline*.
- Guidance on transportation of persons via vessel is provided in the *Code of Practice for Transportation of Employees via Vessel to or from a Workplace.*
- Guidance on transportation of persons via aircraft is provided in the *Code of Practice for Transportation of Employees by Helicopter to or from a Workplace.*
- Guidance on lifting operations for support craft is provided in the *Atlantic Canada Offshore Petroleum Industry Safe Lifting Practice Respecting the Design, Operation and Maintenance of Materials Handling Equipment.*
- Guidance on RPAS is provided in the *Remotely Piloted Aircraft Systems (RPAS) Guideline*. RPAS operations require VMC at all times. Procedures for notification of the aircraft service provider and nearby installations should be in place that describe the time and location (vertical and horizontal limits) of the operation.

i. Description of Support Craft

With respect to paragraph 8(f) of the *Framework Regulations*, operators are required to describe any support craft to be used as part of the application for an OA. This description can be submitted as either as functional specification(s) or as a submission of certification and specifications, as noted below.

ii. Functional Specifications – General – Long-Term Programs

For long-term programs (typically greater than six months) associated with a production project or drilling program, operators should develop functional specifications for support craft used in a work or activity, including aircraft. Functional specifications should take the following into consideration, as applicable:

- Conditions or commitments from associated *Development Plans*.
- Conditions or commitments from associated Environmental Assessments and Impact Assessments.
- Regulatory requirements of the *Regulator* and other authorities.
- Measures or features identified from risk assessments based on the functions the support craft may perform and their interface with the installation or vessel.
- Measures for operation in the foreseeable physical and environmental conditions prevailing in the area in which they operate.
- The minimum type and number of support craft (inclusive of helicopters) that will be required to support operational and emergency operations.
- Certification that will be maintained for each type of support craft.
- Specific performance requirements to be achieved during the program.
- Additional equipment that will be placed onboard based on activity.
- Additional training and competency of persons based on activities being undertaken.
- List of associated operator procedures that will be placed onboard for the program.

iii. Functional Specifications – Aircraft

In addition to the above general requirements, functional specifications for aircraft should also include:

- The requirements of the *Accord Acts*[22] and section 50 of the *OHS Regulations* if it is performing the duties of a passenger craft.
- The requirements of Transport Canada (e.g., *Canadian Aviation Regulations*). The aircraft service provider must possess a valid Transport Canada Operating Certificate for the scope of work to be undertaken and all aircraft should have a Certificate of Airworthiness issued by Transport Canada.
- The scope of all activities that the aircraft will be performing along with any associated requirements to meet the intended function. This should include transit of passengers, cargo transfers, search and rescue operations, inspections, medevac operations and lifting and placement of equipment, as applicable.
- The risk assessment should review and identify measures for the following, as applicable:
    - The remoteness of location and availability of search and rescue resources.
    - Physical and environmental conditions, including sea state, wind, fog, ice and icing conditions, and how these conditions can affect the flight or the ability of the aircraft to land on the water.

[22] C-NLAAIA 205.014(2); CNSOPRAIA 210.014(2)

  - The aircraft's ability to communicate with the shore base, installation(s), other support craft and lifeboats.
  - The ability to rapidly and effectively deploy life rafts and other emergency equipment in the event of an emergency landing on water or a capsize.
  - The ability to escape rapidly and effectively from the interior or the aircraft whether it lands on the water or capsizes.
  - Offshore operational requirements, including physical and environmental condition effects on load limits, flying at night, the transport of passengers and cargo concurrently, minimum amount of fuel to be maintained onboard and any other factor that could affect operational requirements.
- Measures that should be considered include:
  - Identification of critical equipment and redundant equipment.
  - Limitations on the use of the aircraft in varying physical and environmental conditions and provision of additional floatation.
  - Installation of externally mounted life rafts.
  - Configuration and design of aircraft interiors, including doors, windows, upper torso passenger restraints, seat design, etc., to aid in evacuation during landing on water or capsize.
  - Lighting and infrared equipment for conducting rescues or flying passengers at night.
  - Minimum amount of fuel to be maintained at the operations site.
  - Provision of suitable equipment to assist with underwater escape and how this may impact the design and maintenance of the aircraft.
  - Minimum experience of aircraft crews with the type of aircraft in use and with offshore operations in the physical and environmental conditions that may be expected for the area(s) of operation.
  - Commitments respecting the flight time that will be allocated for search and rescue and medevac practice and drills. The allocated flight time should as a minimum provide all crew members with adequate skills and to prevent complacency.
  - The incorporation of automated usage and monitoring systems or other methods to ensure the continued suitability of the aircraft.
  - The associated inspection, testing and maintenance program for the aircraft, additional equipment and associated PPE.

iv. Functional Specifications – Vessels

In addition to the above general requirements, functional specifications for vessels should also include:

- The requirements of the *Accord Acts*[23] and section 51 of the *OHS Regulations* if it is performing the duties of a passenger craft.
- The applicable requirements of flag state and classification societies, including any adopted requirements of IMO.

[23] C-NLAAIA 205.014(2); CNSOPRAIA 210.014(2)

- The scope of all activities that the vessel will be performing along with any associated requirements to meet the intended function. This should include standby duties (including dual standby), passenger transfers, cargo handling (including subsea lifts), anchor handling, towing of an installation or other vessel, ice management, monitoring of deployed equipment (e.g., chase vessel), use of ROVs, GGE or construction activities, as applicable.
- If a vessel is engaged directly in the conduct of seismic, geotechnical, diving or construction activities, it may be considered a marine installation or structure as opposed to a support craft and in this situation, Part III.1 of the *Accord Acts* and the *OHS Regulations* apply.
- Any certificates and class notations to be maintained should be noted in the functional specification. Most certificates require periodic/annual endorsements even though they are issued for 5 years. Up-to-date records of all certificates should be maintained and made available upon request. Certification for the vessel should include, as applicable:
  - Certificate of Class
  - Safety Construction Certificate
  - Safety Equipment Certificate
  - International Load Line Certificate
  - Safety Management Certificate
  - International Ship Security Certificate
  - International Oil Pollution Prevention Certificate
  - International Air Pollution Prevention Certificate
  - International Sewage Pollution Prevention Certificate
  - International Maritime Labour Convention Certificate of Compliance
  - Radio Certificate (A1, A2 and A3)
  - Passenger Certificate, for transportation of passengers
  - Document of compliance (i.e., AC-SBV-DOC) for standby vessels, in accordance with the *Standby Vessel Guideline*. Refer to section 171 of the Framework Guidelines for additional guidance
  - A Letter of Compliance for Coasting Trading License may be required for foreign vessels by Transport Canada. Any specific limitations of use of vessel should be reviewed to confirm it is appropriate for operation in our physical and environmental operating conditions
- Requirements for horsepower, maneuverability, station keeping ability and DP systems (including equipment redundancy for such) and if applicable, capacities for towing/anchor handling, cargo-handling and lifting equipment should be included in the functional specification. When vessels that are interfacing with the installation are not fitted with DP systems, or when the DP system lacks sufficient equipment redundancy (i.e., DP Class 1), the operator should be able to demonstrate that its risk assessment has considered carefully all relevant risk factors and implemented additional measures to mitigate risks associated with prolonged operations near the installation (including fatigue). With respect to DP vessels:

- Refer to the *IMCA M103 Guidelines for the Design and Operation of Dynamically Positioned Vessels* and *IMCA 182 MSF International Guidelines for the Safe Operation of Dynamically Positioned Offshore Supply Vessels.* The configuration of the DP System should be the most robust for the specific activity and be based on a Critical Activity Mode (CAM) study.
- An FMEA should be conducted in accordance with *IMCA M166 Code of Practice on Failure Modes and Effects Analysis (FMEA)* and this should include initial and periodic proving trials, in accordance with *IMCA M190 Code of Practice for Developing and Conducting DP Annual Trials Programmes*.
- If the vessel's DP system is intended to be operated in the closed bus tie mode the operator should ensure that additional mitigations such as advanced generator protection are in place and that the FMEA duly considers harmonic distortion, transient voltage studies and extended protection coordination. For DP Class 2 vessels, it is recommended that the redundant cable routes for data communications networks be physically segregated (this is required by most but not all classification societies).
- Refer to guidance for vessels involved in the towing of an installation in *ISO 19901-6 Petroleum and natural gas industries - Specific requirements for offshore structures - Part 6: Marine operations*.
- The functional specification should specify the minimum number of persons and their associated experience and competence. If the vessel is required to have DP, the persons operating those systems should be identified and properly certified, trained and experienced in accordance with *IMCA M117 Guidelines for the Training and Experience of Key DP personnel*. Additional training requirements are included in COP TQOP which contains requirements for persons onboard standby and supply/support vessels in support of a drilling or production program.
- Support vessels should be operated and maintained in accordance with all applicable international and flag state requirements and the operators' requirements and procedures. It is expected that operating and maintenance procedures will conform to established global industry best practices for Offshore Support Vessels such as the *International Guidelines for Offshore Marine Operations (GOMO)*; however, the operator's procedures and arrangements should address additional unique requirements for the operating area (e.g., adverse physical and environmental conditions, cold water operations, ice navigation and iceberg monitoring/towing).
- Consistent with industry best practices, operators should ensure that operational, environmental and equipment performance limits for the specific location(s) and each specific activity are included in operations manuals for each vessel. Refer to guidance provided in *IMCA M220 Guidance on Operational Activity Planning.*

v. Functional Specifications – General – Short-Term Programs

For short-term programs (typically less than six months), operators may develop a functional specification according to above. Instead of this, the operator may submit specifications and certification for the vessel(s) involved in the program to demonstrate how the requirements have been met.

Section 42 – Observations of Physical and Environmental Conditions

42 An operator must ensure that

- ***(a) physical and environmental conditions, including sea states and ice movements, are observed and forecasts of those conditions are obtained;***
- ***(b) the observations and forecasts are recorded each day, as well as each time there are substantial differences between the observations and the forecasts; and***
- ***(c) the records are maintained at the operations site.***

- Forecasting and observing of physical and environmental conditions should be done in a way that allows an operator to make appropriate operational decisions based on a combined understanding of the limits used in design, and the forecasted and observed physical and environmental conditions at the operational location. An operator may consult the guidance for section 104 of the *Framework Regulations* for a discussion of the relationship between the design and the physical and environmental conditions that may be relevant.
- The operator should be aware of the need to communicate any hazard which may have an impact on safety or protection of the environment pursuant to paragraphs 4(1)(k) and (l) of the *Framework Regulations*. While there is no requirement under section 42 of the *Framework Regulations* to share the specified observations or forecasts with the *Regulator*, the *Regulator* may require such sharing as a condition of approval of an authorization.
- With respect to paragraph 42(c), an operator should refer to the requirements for maintenance of records in section 181 of the *Framework Regulations*.
- Guidance respecting the conduct of forecasting observation, recording, and reporting of physical and environmental conditions is provided in the following:
    - *Manual of Standard Procedures for Observing and Reporting Ice Conditions (MANICE)*
    - *Manual of Marine Weather Observations (MANMAR)*
    - *Manual of Surface Weather Observation Standards (MANOBS)*
    - *Marine Weather Observations*
    - *WMO Manual on Codes, Volume I.1 – International Codes*
    - *WMO Guide to Meteorological Instruments and Methods of Observation, Volume 1 of 5*
    - *WMO Guide to the Implementation of Education and Training Standards in Meteorology and Hydrology*
- o If aircraft are planned to be used, refer to the requirements of the *Canadian Aviation Regulations*.
- For drilling, production and accommodations installations, refer to the requirements and associated guidance for observation, recording, reporting and forecasting of physical and environmental conditions in section 109 of the *Framework Regulations*.

Section 43 – Location of Infrastructure or Equipment

43 An operator must keep data or information that accurately describes the location of any infrastructure or equipment at an operations site that is on or attached to the seabed, including any abandoned installation or part of it.

No guidance required at this time.

Section 44 – Accessibility, Storage and Handling of Consumables

44 An operator must ensure that explosives, fuel, spill-treating agents, spill containment products, drilling, completion and well stimulation fluids and cement, as well as chemicals and other consumables that are necessary for safe operations, are
(a) readily accessible and stored in quantities that are sufficient for normal conditions and any emergency situation; and
(b) stored and handled in a manner that does not create a hazard to safety or the environment, including any hazard that could result from their deterioration.

The determination of minimum amounts should consider the ability to replenish the supplies of consumables given the remoteness of the area of operations, the physical and environmental conditions that may affect supply, the re-supply capability and the maximum expected consumption levels. In assessing these minimum amounts, the following should also be considered:

- Refer to the requirements and associated guidance for compressed gas, explosives and hazardous substances under Parts 28, 30 and 31 of the *OHS Regulations*, respectively.
- With respect to paragraph 44(b) of the *Framework Regulations*, refer to the requirements and associated guidance for storage and handling under section 45 of the *Framework Regulations*.
- With respect to the amount of firefighting foam concentrate, refer to the guidance referenced under sections 174 - 176 of the *Framework Regulations* for landing areas.
- With respect to subsection 174(1) of the *Framework Regulations*, the amount of reserve aviation fuel to be kept onboard installations and the rationale used to arrive at this amount.
- For drilling, production and accommodations installations, refer to the requirements and associated guidance for fire protection systems under section 130 of the *Framework Regulations*.

Section 45 – Storage and Handling of Chemical Substances

45 An operator must ensure that all chemical substances present at an operations site, including process fluids, fuel, lubricants, waste material, drilling fluids and drill cuttings, are stored and handled in a manner that does not create a hazard to safety or the environment.

- An operator should assess the risk associated with chemical substances at an operations site and implement all measures necessary to mitigate risks associated with those chemical substances whether they are brought onboard or generated at the location. For new build installations, operators should also assess the risk at an early stage in the design of the installation and processes. With respect to chemical substances, operators should implement a hierarchy of controls as follows:
    - Eliminate the hazards associated with the use of chemical substances by eliminating the chemical if its use can be avoided.
    - Substitute with alternatives that provide better protection to persons and the environment.
    - Reduce the amount that is used or stored at the operation site, considering its placement and interaction with persons, other materials, equipment or the environment.

- The following should also be considered:
    - The definition of “hazardous substances” and associated requirements under Part III.1 of the *Accord Acts.*
    - Refer to the requirements and associated guidance for compressed gas and hazardous substances under Parts 28 and 31 of the *OHS Regulations.*
    - With respect to a drilling, production or accommodations installation, the requirements under sections 107, 113 and 115 of the *Framework Regulations* for fire, explosion and hazardous gas risk assessments, classification of hazardous and non-hazardous areas and ignition prevention, inclusive of storage and containment considerations.
    - The *Transportation of Dangerous Goods Act* and the associated regulations, IMDG and the IATA *Dangerous Goods Regulations.*

- Any discharges may only be done in accordance with the Environmental Protection Plan submitted under section 10 of the *Framework Regulations.*
- The handling (e.g., use, discharge or transport) of chemical substances must also be done in accordance with the requirements of other provincial and federal authorities. Other authorities may require additional measures to be put in place or require notification. Some examples of notifications to other authorities, include:

- For use of explosives subsea (inclusive of severing wellheads) as necessary, the operator should notify the *Regulator* and any other agencies, as applicable, of the expected timing of the operation and the type and amount of explosives to be used.
- For planned releases of cement, firefighting foam or any other chemical into the environment, the operator should also notify the CCG and other agencies, as applicable.

In the event that explosives are used, and in accordance with any requirement of an associated Environmental Assessment and Impact Assessment, explosive operations should not be undertaken when marine mammals are within one kilometre of the installation or vessel.

Section 46 – Misuse of Equipment

46 It is prohibited for any person to tamper with, activate without cause or otherwise misuse equipment that is necessary for safety or the protection of the environment.

No guidance required at this time.

Section 47 – Cessation of a Work or Activity

47 (1) An operator must ensure that any work or activity ceases without delay if it
(a) endangers or is likely to endanger the safety of any other work or activity;
(b) endangers or is likely to endanger the safety or integrity of any operations site or well; or
(c) causes or is likely to cause pollution.

Conditions for resumption

(2) The operator must ensure that the work or activity does not resume until it can be done safely and without causing pollution.

No guidance required at this time.

Section 48 – Document Availability

Copy of authorizations and approvals

48 (1) The operator must ensure that a copy of the authorization and all related approvals that are required under these Regulations or Part III of the Act is displayed in a conspicuous location at every operations site.

(2) An operator must keep an additional copy of the authorization and approvals, as well as all plans that are required under these Regulations or Part III of the Act, at every operations site and must ensure that they are readily accessible for consultation or examination.

Posting of Information

Operators must post onboard the installation or vessel the information prescribed by the *Accord Acts*[24], that has been prescribed to be posted in either the *Framework Regulations* (e.g., OAs, approvals) or the *OHS Regulations* (e.g., life-saving plans, station bills) or that has been prescribed to be displayed conspicuously as a requirement of the *Regulator*.

Document Availability

Operators must make available any information that has been prescribed by the *Accord Acts*[25] or that has been prescribed to be made readily available in either the *Framework Regulations* (e.g., Safety Plan, Environmental Protection Plan, Contingency Plan) or the *OHS Regulations*. The operator should also make available in printed or electronic form at the workplace, the following information:

- The *Accord Acts* and associated regulations.
- Documentation in relation to the OA and other related approval(s) that have been granted by the *Regulator* (including *Development Plans* and associated conditions if applicable, RQs, etc.).
- The COF issued by a CA, if applicable and any related attachments, including current list of limitations.
- If information is required to be made available according to a code or standard that has been adopted, then this information should also be made available.

[24] C-NLAAIA 205.037(1), 205.038(1); CNSOPRAIA 210.037(1), 210.038(1)
[25] C-NLAAIA 205.037(2), 205.038(2); CNSOPRAIA 210.037(2), 210.038(2)

Section 49 – Emergency Response Procedures and Other Documentation

49 An operator must ensure that a copy of the most current version of the emergency response procedures and any documentation that is necessary to carry out an authorized work or activity and to operate and maintain an installation or pipeline is
(a) readily accessible at all times at every operations site and emergency response operations centre; and
(b) usable under all foreseeable circumstances at each location referred to in paragraph (a).

Refer also to the requirements and additional guidance for document availability provided under section 48 of the *Framework Regulations*.

Controlled Documents

With respect to sections 48 and 49 of the *Framework Regulations*, documented information (whether in printed or electronic format) should be maintained up-to-date and readily available when required. Documented information would normally include any plans, operations and maintenance manuals, policies, procedures, work instructions, checklists, diagrams, layout drawings, piping and instrumentation drawings, electrical and instrumentation schematics, manufacturer information, safety data sheets, etc. Additional guidance on maintaining control of documents is provided in Part 3 of the *Framework Regulations*.

Hardcopy Documents

The operator should ensure that hardcopy versions of required documents are maintained at the onshore and offshore emergency response centres (including alternative locations), control rooms/bridge, medical room or any other area that may need information available during any foreseeable event. This should also consider whether the document should be available in the event there is a loss of power, loss of lighting or other technology issues. In addition, any key operational documentation or Contingency Plan(s) should also be made available to support craft.

Section 50 – Plans

Implementation

50 (1) An operator must ensure that the safety plan referred to in section 9, the environmental protection plan referred to in section 10 and the resource management plan referred to in section 25 are implemented at the commencement of any work or activity and that the

contingency plan referred to in section 11 is implemented as soon as an accidental event occurs or appears imminent.

Periodic updates

(2) The operator must ensure that the safety plan, environmental protection plan, resource management plan and contingency plan are periodically updated; however, the descriptions of installations, vessels, systems and equipment that are included in the safety plan and environmental protection plan as required by paragraphs 9(2)(c) and 10(2)(c), respectively, must be updated as soon as the circumstances permit after the modification, replacement or addition of any major component.

With respect to subsection 50(2) of the *Framework Regulations*:

- The documents required to be submitted as part of the application for an OA and the commitments made in those documents will remain enforceable until the operator submits an amended document to the *Regulator* for review and the *Regulator* amends the OA to replace the previous version with the accepted one.
- While the frequency of periodic updates to these plans is not specified in the *Framework Regulations*, there are requirements within the *Accord Acts* and associated regulations that specify when certain reviews are to be undertaken and there are also requirements to continually improve the management system. If changes are made, as part of the management of change process, a review of impacts on the content contained within these plans should be undertaken.
- With respect to modifications and replacements, notification must be made to the *Regulator* pursuant to section 162 of the *Framework Regulations*. The operator should determine if any changes are required to these plans and should submit those revised documents with that notification.

PART 7: GEOSCIENTIFIC, GEOTECHNICAL AND ENVIRONMENTAL PROGRAMS

Section 51 – Measures

Measures

51 An operator must ensure that
(a) all equipment and materials that are necessary to conduct a geoscientific program, geotechnical program or environmental program are handled, installed, inspected, tested, maintained and operated in a manner that takes into account the manufacturer's instructions and industry standards and best practices; and

(b) if any of the equipment, its components or the materials are defective, they are, without delay, repaired or replaced in accordance with the manufacturer's recommendations.

a. Geoscientific Programs

With respect to equipment and materials, and the training and procedures for the use of these equipment and materials in geoscientific programs, the operator should consider the guidance provided in the following:

- Part 5 of the *IAGC Marine Safety Manual for Worldwide Geophysical Operations*.
- Table 2 and sections 2.14, 2.15, 2.16, 2.17, 2.25, 2.26, 2.27 and 2.28 of *IOGP Report 432 HSE Managing HSE in a Geophysical Contract*.
- *IAGC Environment Manual for Worldwide Geophysical Operations.*
- *Statement of Canadian Practice with respect to the Mitigation of Seismic Sound in the Marine Environment.*
- For an airborne program, the following should be considered:
  - Installation of alarms for low altitudes to mitigate hazards associated with flying at low altitudes, to address low visibility because of fog and the potential for collision with installations, vessels, other aircraft or icebergs.
  - Interference with height requirements for bird colonies, migration paths and protected areas.
  - Operational limits established and documented in operational procedures for all foreseeable physical and environmental conditions that may impact safety or quality of data collection, including flying in low visibility.
  - Transport Canada's *Canadian Aviation Regulations* as they pertain to the aircraft, associated training or instruction, observations and forecasts of physical and environmental conditions, operating procedures and associated limitations.

b. Geotechnical Programs

With respect to equipment and materials, and the training and procedures for the use of these equipment and materials in geotechnical programs the operator should consider guidance provided in *ISO 19901-8 Oil and gas industries including lower carbon energy — Offshore structures — Part 8: Marine soil investigations.*

c. Environmental Programs

With respect to equipment and materials, and the training and procedures for the use of these equipment and materials in environmental programs, the operator should consider guidance provided in *Regional Guidance on Measures to Protect Corals and Sponges During Exploratory Drilling in the Canada-Newfoundland and Labrador Offshore Area*. Additional guidance is also provided in *Canadian Technical Report of Fisheries and Aquatic Sciences 3578: Preparing for Remotely Operated Vehicle (ROV) Seafloor Surveys*.

Section 52 – Certification

52 An operator must ensure that a competent third party has certified that all equipment that is installed temporarily on a vessel to conduct a geoscientific program, geotechnical program or environmental program is fit for the purposes for which it is to be used.

With respect to the installation of equipment, including sea fastening, the competent third party can be the classification society, marine warranty surveyor or other party that can verify that the equipment has been properly designed and installed. This includes the certification of equipment such as pressure systems, materials handling equipment, electrical systems, etc.

Equipment must also meet the applicable requirements of the *OHS Regulations* (e.g., hazardous substances, hazardous energy) and any applicable requirements of Part 6 of the *Framework Regulations*. The competent third party should also verify that the equipment has been properly designed and installed in accordance with the requirements of the *OHS Regulations*.

Section 53 – Damage to Property

53 An operator must take all necessary measures to ensure that no property is damaged as a result of a geoscientific program, geotechnical program or environmental program.

- Property is interpreted to include fishing gear, vessels, buoys, moorings, etc.
- Operators should implement a damage compensation program, to promptly settle claims for loss or damage to equipment or vessels that may be caused by survey operations. The scope of the compensation program should include replacement costs for lost or damaged equipment (e.g., fishing gear) and any additional financial loss that is demonstrated to be associated with the incident. The operator should report on the details of any compensation awarded under such a program.
- Procedures should be in place to ensure that any incidents of contact with equipment (e.g., fishing gear) are clearly detected and documented (e.g., exact time and location of initial contact and loss of contact, description of any identifying markings observed on affected gear, photo). If an operator comes across non-active fishing gear, contact should be made with DFO. Non-active fishing gear should not be removed unless otherwise directed by DFO.
- For reporting of damages to property, refer to the *Incident Reporting and Investigation Guideline*.
- Refer to the *Compensation Guideline Respecting Damages Relating to Offshore Petroleum Activity*.

Section 54 – Energy Sources

General Requirements

54 (1) An operator must ensure that any energy source that is used in a geoscientific program, geotechnical program or environmental program is
(a) kept free from any substance that could create a hazard; and
(b) operated in a manner that prevents inadvertent activation of the energy source.

Electrical or electromagnetic energy source

(2) The operator must ensure that any electrical or electromagnetic energy source is equipped with circuit breakers on the charging and discharging circuits and with wiring that is adequately insulated and grounded to prevent current leakage and electrical shock.

Elimination of risk to divers

(3) The operator must ensure that the program is conducted in a manner that eliminates all safety risks to divers from any energy source used, including by determining the minimum distances that are required to be maintained between the divers and the energy source and ensuring compliance with those distances.

- Refer to requirements and associated guidance under section 51 of the *Framework Regulations.*
- With respect to subsection 54(3) of the *Framework Regulations*, activities should be avoided within 10 kilometres of a diving activity. Refer to requirements and associated guidance under paragraph 165(o) of the *OHS Regulations*.

Section 55 – Testing of Energy Sources

55 (1) An operator must minimize energy source testing on the deck of an operations site while a geoscientific program, geotechnical program or environmental program is being conducted.

Energy source activation

(2) Before an energy source is activated for testing purposes, the operator must ensure that measures are taken to protect persons at the operations site where the test will be conducted from exposure to any hazard associated with the energy source, including:

(a) advising those persons that a test will be conducted;
(b) safely securing all equipment; and
(c) in the case of an electrical or electromagnetic energy source, fully immersing it in water.

- Refer to the requirements under section 11 of the *Framework Regulations* and associated guidance in the *Contingency Plan Guideline* for typical measures that should be implemented while conducting these activities near other activities (e.g., simultaneous activities).
- Refer to the requirements and associated guidance under section 51 of the *Framework Regulations* for typical measures that should be implemented while conducting these activities.
- An operator may only deploy equipment for testing within the temporal and spatial scope described for the program in the associated Environmental Assessment and Impact Assessment.

Section 56 – Classification of Primary Vessel

56 An operator must ensure that the primary vessel used in a geoscientific program, geotechnical program or environmental program holds a valid certificate of class issued by a classification society.

- Refer to flag state and classification society rules.
- Refer to applicable requirements of IMO, including SOLAS and associated IMO circulars or resolutions.
- Vessels should be suitable for operations in the environment they are intended to work in and operational limits should be established, communicated and adhered to during the program.

Section 57 – Destruction, Discard or Removal from Canada

Prohibited without approval

57 (1) It is prohibited for any person to destroy, discard or, subject to subsection (2), remove from Canada the following materials and information that are obtained in the context of a geoscientific program, geotechnical program or environmental program unless the destruction, discard or removal is approved by the Board under subsection (3):
(a) all field data and final processed data that are in a digital format, together with a description of that data format;
(b) any samples; and

(c) all other data, observations, readings and supporting information obtained during the program.
Exception

(2) The materials and information may be removed from Canada without the approval of the Board for the purpose of being processed in a foreign country if they are returned to Canada as soon as the processing is complete.

Approval of application

(3) Within 60 days after the day on which the Board receives an application for approval to destroy, discard or remove from Canada materials or information, the Board must approve the application if the Board is satisfied that the materials or information are not of much use or value.

Provision of materials or information

(4) The Board may, after receiving an application referred to in subsection (3), require that the materials or information, or a copy of the information, be provided to the Board within the period that it specifies.

With respect to the removal of data and other information from Canada, this request should include information on the location of the data or material and an estimation of when the data or materials will be returned to Canada. With respect to cloud storage outside of Canada, this request should include an estimation of when the data will be accessible, if required.

PART 8: DRILLING AND PRODUCTION PROGRAMS

Section 58 – Allocation of areas

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58 The Board may make orders respecting the allocation of areas, including respecting the determination of the size of spacing units and the determination of well production rates, for the purpose of drilling for or producing petroleum.

No guidance necessary at this time.

Section 59 – Name, Classification or Status of Well

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

Classification of Wells

Consistent with the *Accord Acts*, there are three types of well classifications:
- Exploration
- Delineation
- Development

The well classification is determined by the *Regulator* based on the original purpose of the well. However, the *Regulator* may modify a well's classification based on change in purpose of that well (e.g., delineation well was subsequently completed and used as a development well). The *Regulator* will notify the operator of any change in well classification. Where possible, operators should describe all targets upon submitting an ADW to enable the *Regulator* to properly classify well data and assign appropriate data release date(s).

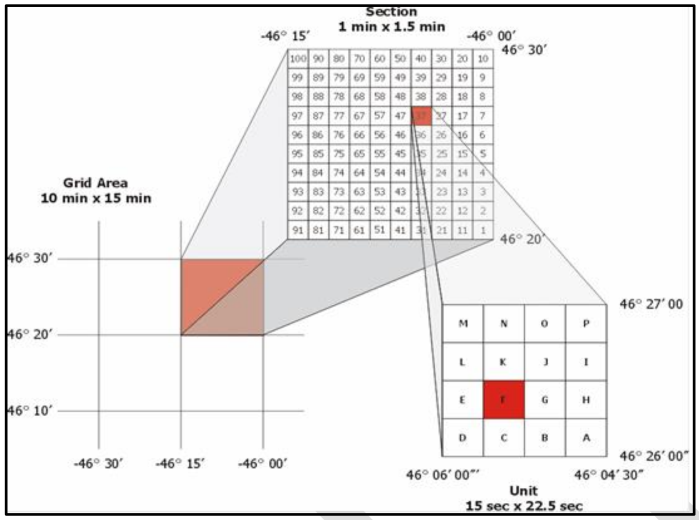
Status of Wells

The *Regulator* 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 *Regulator* could modify the status of the well from suspended to abandoned and would notify the operator of the change.

Naming of Wells

The *Regulator* uses the federal land division system for naming wells. This system includes 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 additional information on the federal land division system refer to the *Canada Oil and Gas Land Regulations* and associated guidance on NRCAN's website.

Federal land division system for naming a well



Wells are named referencing the unit and section at the surface location of the well (e.g., for well F-37, F is the unit and 37 is the section at the surface location of the well – see diagram above).

The operator should identify a name for the well using the well naming convention noted by each *Regulator* below when the application for an ADW is submitted. The well name is reviewed by the *Regulator* and if appropriate, it becomes the official well name. If an operator incorrectly assigns the well name, it will be corrected by the *Regulator* 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 and should be used on all correspondence in relation to that well.

A well is considered sidetracked when it deviates from the original well-bore. If the original ADW does not include sidetracks, a revised or new ADW must be filed with the *Regulator* in support of a sidetracked well. Where multi-laterals are planned, the sidetrack designator will only be issued once the subsequent hole section has successfully reached total depth according to the ADW, to allow for unforeseen sidetracks that may result from operational issues experienced while drilling. If a well is sidetracked or re-spudded then an additional letter is added to the name to differentiate the sidetrack from the parent well. Wells in NL use reverse alphabet notation (i.e., Z, Y, X…) to denote the sidetracked well-bore, whereas, wells in NS use forward alphabet notation. (i.e., A, B, C…). If there is an unplanned sidetrack that needs to be abandoned it will still be assigned a letter in sequence. All drilling needs to be recorded.

Exploration and Delineation Wells

There are different well naming conventions used between the C-NLOPB and CNSOPB for sidetracks as follows:

C-NLOPB

Where a well is sidetracked either for unforeseen or planned reasons, reverse alphabet notation is used to denote the sidetracked well-bore. 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	1^{st} sidetrack (2^{nd} - Y; 3^{rd} - X; etc.)

CNSOPB

Where a well is sidetracked either for unforeseen or planned reasons, forward alphabet notation is used to denote the sidetracked well-bore. 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	1^{st} sidetrack (2^{nd} - B; 3^{rd} - C; etc.)

Development Wells

The common surface location naming convention is used to identify development wells associated with producing fields. Wells drilled from a fixed platform will take the unit and section number associated with the platform installation. Wells drilled from a subsea template will take the unit and section number associated with the drill centre in which the template is located. Where a subsea satellite well (i.e., a stand-alone well) is drilled and tied back to a drill centre by flowline, the well unit and section number must be associated with the surface location of the well and not the location of the drill centre.

To differentiate development wells drilled from a common surface location, a well designator is assigned based on the sequence in which an ADW application is received. The well designator is the number that follows the unit and section number in a well name i.e., Galaxy Oil et al. Pluto F-29 2 represents the second ADW application received from the operator in respect of the development.

There are different well naming conventions used between the C-NLOPB and CNSOPB for sidetracks as follows:

C-NLOPB

Where a well is sidetracked either for unforeseen or planned reasons, reverse alphabet notation is used to denote the sidetracked well-bore. 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 and its partners
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 *Regulator* (i.e., 4th development well drilled from F-29 surface location)
Z	1st sidetrack (2nd - Y; 3rd - X; etc.)

CNSOPB

Where a well is sidetracked either for unforeseen or planned reasons, forward alphabet notation is used to denote the sidetracked well-bore. 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 and its partners
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 *Regulator* (i.e., 4th development well drilled from F-29 surface location)
A	1st sidetrack (2nd - B; 3rd - C; etc.)

Multilateral Wells

For multilateral wells, the same notation sequence is used as for sidetracks. For example, in NL, the first lateral (or mainbore) will be F-29 4, second F-29 4Z, third F-29 4Y. In NS the first lateral (or mainbore) will be F-29 4, second F-29 4A, third F-29 4B.

All Wells

In NL, for all wells, where a well is re-spudded, the digit 2 would be used as a designator for the first re-spud, 3 for the second re-spud, etc., and would precede the unit letter. For example Galaxy Oil et al. Pluto 2F-29 would be the first re-spud of Galaxy et al. Pluto F-29. If the well was subsequently sidetracked it would be Galaxy Oil et al. Pluto 2F-29Z.

Section 60 – Pool, Zone or Field

60 The Board may
(a) designate a zone as such for the purposes of these Regulations;
(b) give a name to a pool, zone or field and change that name; and
(c) define the boundaries of a pool, zone or field.

If the names and boundaries for each pool, zone or field are not finalized before submission of a *Development Plan*, a proposal for such should be included with the *Development Plan*.

Pools

The *Regulator* will consult with the operator on the naming and boundaries of a pool. The following is a typical process for pools:

- *Regulator* and operator conduct independent assessments of pools within a field;
- operator submits proposed pool name and boundaries to the *Regulator*;
- *Regulator* reviews the proposal and meets with the operator, if necessary, to address any disagreements;
- the *Regulator* will notify the operator of the pool name and boundaries; and
- adjustments will be made to pool name and boundaries, as necessary, based on new information acquired through drilling and production in consultation with the operator.

An operator is not required to submit a proposal for pool boundaries and naming. However, if a proposal is submitted, it should:

- provide a brief description of the reservoir and proposed pools;

- present evidence for 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 each pool;
- for each well drilled into the pool, provide the depths (e.g., MD, TVD and TVD–subsea (TVD-SS) to the top and base of each pool;
- provide a structural cross-section through the reservoir interval, that includes all wells that penetrate the proposed pool(s); and
- other information, if available, in support of proposed pool designation including:
  - fluid contacts defined by:
    - logs;
    - core; and
    - pressure data (e.g., wire line, formation flow test);
  - reservoir pressure data;
  - fluid analysis;
  - geologic data to assess barriers to vertical and lateral flow including fault seal analysis, reservoir quality and distribution, facies maps, logs, cores and drill cuttings;
  - seismic data; and
  - production logs and data acquired from cased hole logs and the annual pool pressure survey.

Zones

The *Regulator* may name or designate a zone within a pool or field and may define its boundaries. The *Regulator* 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.

Pooling re-designation within a field may take place at any time during the life of a field when production monitoring suggests that pre-production pooling designations were incorrect and need to be changed.

Refer to the definition of "pool" and "field" in the *Accord Acts* and the definition of "zone" provided in section 1 of the *Framework Regulations*.

Allocation

When a pooling change or zonal designation has been made by the *Regulator*, the operator of a pool will be required to allocate production to the *Regulator* on a go-forward basis. 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 *Regulator* 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 better resource management and prevention of waste during the entire life of the field.

EVALUATION OF WELLS, POOLS AND FIELDS

Section 61 – Data Acquisition Programs

61 (1) An operator must ensure that the field data acquisition program referred to in section 13 and the well data acquisition program referred to in section 18 are implemented in accordance with good oilfield practices.

Partial implementation

(2) If part of the field or well data acquisition program cannot be implemented, the operator must ensure that
(a) a conservation officer is notified as soon as the circumstances permit;
(b) measures to otherwise achieve the goals of the program are submitted to the Board for approval; and
(c) the measures approved by the Board are implemented.

Board approval of alternate measures

(3) The Board must approve the measures submitted under paragraph (2)(b) if the operator demonstrates that the measures can achieve the goals of the field data acquisition program or the well data acquisition program, as the case may be, or are the only ones that can be taken in the circumstances.

Periodic updates

(4) The operator must ensure that the field data acquisition program is periodically updated.

Refer to the *Data Acquisition Guideline.*

Section 62 - Formation Evaluation, Testing and Sampling

62 If the Board determines that data or samples from a formation in a well would contribute substantially to the geological and reservoir evaluation, the operator must ensure that the formation is evaluated, tested and sampled as necessary to obtain the data and samples.

Refer to the *Data Acquisition Guideline*.

Section 63 – Formation Flow Test

63 (1) An operator must ensure that no development well is put into production unless a formation flow test that has been approved by the Board under subsection (5) is conducted.

Well operation

(2) If a development well is subjected to a well operation that might change its deliverability, productivity or injectivity, the operator must, for the purpose of determining the effects of the operation on the well's deliverability, productivity or injectivity, ensure that a formation flow test that has been approved by the Board under subsection (5) is conducted as soon as the circumstances permit after the well operation has ended and the flow or injection conditions have stabilized.

Conditions

(3) Before conducting a formation flow test on a well drilled on a geological feature, the operator must
(a) submit a formation flow test program to the Board; and
(b) obtain the Board's approval under subsection (5) to conduct the formation flow test.

Contribution to geological and reservoir evaluation

(4) 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 the Board determines that the test would contribute to the geological and reservoir evaluation.

Approval of formation flow test

(5) The Board must approve a formation flow test if the operator demonstrates that the test will be conducted in a manner that ensures safety and the protection of the environment and in accordance with good oilfield practices and that the test will enable the operator to
(a) obtain data on the deliverability of the reservoir and the productivity of the well;
(b) establish the characteristics of the reservoir; and
(c) obtain representative samples of the formation fluids.

Approval of a Formation Flow Test Program for Development Wells

Operators should carry out a formation flow test in development wells:

- upon initial completion of the well within two months of establishing stabilized production from or injection into a well; and
- following a well operation that could change either the productivity, deliverability or injectivity of the well, within a reasonable timeframe following the well operation.

Flow tests are not required for disposal (e.g., cuttings re-injection) wells.

The program for formation flow testing of development wells should be submitted as part the FDAP required in support of the issuance of an authorization. The formation flow test program should be standardized and outline the following:

- Test objectives for producers and injectors.
- List flow/injection and shut-in periods.
- Reference to equipment and procedures to be used in conducting the test.

The program for testing wells must be approved by the *Regulator* before a well can be placed into production. When a standard test program has been provided in the FDAP, an operator need only reference this program in the ADW for approval. For wells in which an operator decides to deviate from a standard test program, an operator should submit, for approval, a separate test program, specific to the objectives and uncertainties of the well.

Some additional notes:

- Shut-in Duration - Following flow or injection periods in both producers and injectors, shut-in duration should be sufficient to permit the determination of average reservoir pressure in support of the Annual Pool Pressure Survey described in section 4.6.2 of the *Data Acquisition Guideline.*
- Commingled Production - When production from two or more pools or recognized zones are to be commingled, testing should be conducted in a manner that will enable an assessment of reservoir characteristics, and the deliverability or productivity of each pool or zone. This assessment may be conducted by first testing each pool or zone separately, or by a commingled test where supported by cased hole production logging.
- Subsea Developments - Testing from a MODU is discouraged to avoid unnecessary flaring and environmental risks. The operator of subsea development wells should, where possible, defer formation flow testing to the production facility. Consequently, expectations noted above regarding testing and cased-hole logging in support of commingled pools or zones is waived. In its place, an operator will be expected to prorate test results to a pool or zone employing inferred porosity-permeability relationships.
- Testing of Secondary Horizons - Given that the primary focus of development wells is the exploitation of approved development horizons, the *Regulator* would limit any evaluation requirements respecting the testing of secondary horizons to coincide with requests for

abandonment or reuse of the well-bore. The operator should be prepared to test secondary horizons to effect an appraisal of the significance of these horizons before abandonment or reuse of the well. To this end, testing considerations should address the uncertainties identified typically for delineation wells. The *Regulator* recognizes the operator's need to customize test design specific to the well and situation.

- Fluid Samples - Notwithstanding the operator's requirements for fluid samples, the operator should collect for submission to the *Regulator* one set of samples, in respect of formation flow tests conducted on secondary reservoirs being appraised to assess development potential.

Approval of a Formation Flow Test Program for Exploration or Delineation Well

While there is no regulatory requirement to conduct a test in an exploration well, a formation flow test is required on a well for which an application for significant discovery declaration is made pursuant to the *Accord Acts*[26]. For delineation wells, an operator should conduct testing in select wells when such testing could resolve technical and economic uncertainties respecting the evaluation of a reservoir interval or the development of a pool or field. To this end an operator is encouraged to discuss its delineation plans for a field with the *Regulator* before drilling.

For exploration and delineation wells, the operator should indicate its intent to conduct a formation flow test in its WDAP submitted in support of section 18 of the *Framework Regulations*. If the intent is to conduct a formation flow test on an exploration or delineation well, the operator may later decide to abstain from testing and abandon the well, or defer testing by suspending the well in a manner that would allow the well to be re-entered and tested later. To facilitate early review of a test program, the operator will be expected to engage with the *Regulator* before approval of the ADW.

The *Regulator* or the operator may request that one of the *Regulator*'s conservation officers witness a formation flow test in respect of a potential Significant Discovery Application.

For the purposes of exploration and delineation wells, there are two acceptable means of meeting subsection 63(5) of the *Framework Regulations*:

- Conventional cased-hole testing (e.g., drill stem testing).
- IPTT, that includes the use of tools capable of providing zonal isolation and allowing fluid flow circumferentially from the reservoir.

In developing a program the following should be considered:

- Any proposed formation flow test that includes flaring must have been described in the associated Environmental Assessment and Impact Assessment and be conducted subject to any conditions in a Decision Statement issued by the Minister of ECCC in respect of that drilling program, or in NL, for exploratory drilling, the *Regulations Respecting Excluded*

[26] C-NLAAIA 47, 71, 72; CNSOPRAIA 49, 74, 75

Physical Activities (Newfoundland and Labrador Offshore Exploratory Wells), as the case may be.

- Equipment must comply with the requirements of Part 10 of the *Framework Regulations*. Refer to the requirements and associated guidance for safety and environmental protection, physical and environmental conditions, materials, hazardous and non-hazardous areas, ventilation, ignition prevention, escape routes, electrical systems, control and monitoring systems, general alarm systems, gas release systems, fire and gas detection, emergency shutdown systems, fire protection systems, pressure systems, mechanical equipment, operations manuals, maintenance programs, and drilling risers as provided in sections 98, 104, 106, 107, 111, 113, 114, 115, 118, 122, 123, 124, 125, 130, 131, 132, 133, 134, 135, 136, 157, 159 and 164 of the *Framework Regulations.* In particular, refer also to the requirements and associated guidance for well control equipment and formation flow test equipment under section 68 and 167 of the *Framework Regulations*. All equipment, including equipment used to evaluate the formation, should be fit for the purposes for which it will be used.
- The operator must confirm that there are no outstanding limitations with respect to the equipment or the formation flow testing area on the COF issued by the CA.
- If information is already described in documentation that forms part of an application for an OA (e.g., Safety Plan, Environmental Protection Plan, Contingency Plan), the application for formation flow test program should make reference to it rather than duplicate the information. If there are any details noted below that are not included in that documentation, then relevant details should be included in the application.
- Guidance for formation flow test programs is provided in the following:
    - *NORSOK D-007 Well testing, clean-up and flowback systems*
    - *NORSOK D-010 Well integrity in drilling and well operations*

Content of conventional cased-hole testing programs

A conventional cased-hole testing program should include the following:

- A description of each interval to be tested, including:
    - MD to the top and base of the interval to be tested;
    - shot density of interval perforated referenced to the primary depth control log for the well;
    - estimates of reservoir temperature and pressure, porosity and water saturation; and
    - reservoir fluid expected, including estimates of fluid properties where available.
- A description of the objectives of the testing program, and the procedures to be used in conducting, controlling and terminating the test, including:
    - A list of all flow and shut-in periods planned including proposed durations, and associated period objectives as presented in Table A1 of Appendix A. The duration for the secondary flow period should not exceed four days unless otherwise approved by the *Regulator*. This limitation is intended to minimize prolonged environmental or safety risks with respect to prolonged flaring operations.
    - The operator’s criteria for stabilized rate of flow for anticipated or marginal conditions.
    - A description of all fluids (e.g., cushion fluid, packer fluid) used in conducting the test.

  - A description of the expected fluid to be produced and its properties, including temperature, pressure and any chemicals (e.g., H_2S, CO_2) produced that may impact equipment.
  - The proposed fluid sampling program and sampling procedures. An operator should obtain samples of each fluid produced during a formation flow test for all wells in sufficient volumes and using techniques to permit the analysis required by section 61 of the *Framework Regulations*. This should include submission of one set of atmospheric samples consisting of samples of each liquid produced (oil, or condensate and water) from each test to the *Regulator*. Each sample should be at least 4 litres. Samples of produced gas need not be collected unless specifically requested by the *Regulator*.
  - Data gathering and reporting procedures.
- A description of the equipment to be used in the test progam, including:
  - Schematics and description of associated well control equipment, trees, valves, chemical injection system, the landing string assembly and bottom hole string assembly, including a description regarding the functioning of each tool used in the assembly and relevant injection points/depths. Relevant pressure, temperature and metallurgical properties (e.g., H_2S ratings) of equipment should be included. A description the program for ensuring downhole assemblies are designed to be shearable, and for equipment that is non-shearable, a reference to the program for proper space out of equipment across BOP(s). This should also include a description of any features and capabilities to prevent uncontrolled well flow in the event of an emergency disconnect.
  - Schematics and description of associated surface equipment showing the flow paths for produced fluids (i.e., gas, oil, condensate and produced water), including the flow path of fluids used in assisting production (i.e., artificial lift operations). Relevant pressure, temperature and metallurgical properties (e.g., H_2S ratings) of equipment should be included.
  - Specifics associated with all proposed downhole gauges (e.g., location in the string, sampling frequency, accuracy, resolution, and provision for measurement verification).
  - A description of how the system has been integrated with other systems onboard the installation (e.g., control and monitoring system, electrical systems, emergency shutdown systems).
  - A description of the proposed equipment pressure tests and calibration program of gauges used in the program.
  - A description of the readiness checks for equipment before testing, including checks of the surface and subsurface equipment, controls and monitoring systems, emergency shutdown system, flaring system and other equipment to be used.
- A description of the risks and associated measures put in place. Some typical measures that should be included are as follows:
  - Conducting drills and exercises to test preparedness for emergency events.
  - Conducting a pre-flare meeting immediately before the test to review testing procedures, discuss emergency response measures and to ensure that relevant persons understand their roles and responsibilities.
  - Supervisors being present on the deck during the test.

- Conducting the test in mild physical and environmental conditions with limited motions of heave, pitch and roll.
- Conducting the initial flow to surface during daylight hours. (NOTE: Subsequent secondary flows associated with the same test are permitted during hours of darkness in which adequate illumination (i.e., artificial lighting) is provided over the testing area, including the area of the flare boom and surrounding dropout area on the ocean surface.
- Maintaining a flare watch for the early detection of spills.
- Ensuring that adequate illumination is provided over the testing area, including the area of the flare boom and the ocean beneath the flare boom.
- Ensuring that flaring radiation levels are maintained to acceptable limits for persons and equipment, including description of any measures to be implemented during flaring such as employing water sprays or barriers.
- Ensuring that redundant or highly reliable arrangements are in place for flaring.
- Ensuring that the risk of ignition is reduced to ALARP (e.g., refer to the requirements and associated guidance provided in section 115 of the *Framework Regulations*).
- Ensuring that aircraft does not land during flow periods.
- Ensuring that equipment is not lifted over the surface equipment during the testing operation.
- Ensuring that equipment is ready for well killing operations.
- Notification to the standby vessel and other support craft in the area regarding the start of the testing operation.
- Notification to CCG before testing.
- Implementing pre-flare checklists to ensure all safety and environmental protection measures are in place before initiating flaring operations.

- A description of the procedures in place and the key steps for conducting the test, including any physical and environmental condition or operating limits for conducting the program. This should also include the procedures in place for management of hydrates.
- A reference to applicable emergency response procedures and Contingency Plans in place and to any additional emergency preparedness measures in place specifically for testing operations (such as measures for heave compensation failure, adverse physical and environmental conditions, etc.). Measures should also be in place to suspend flaring operations in the event of a spill.
- A description of the roles and responsibilities of key persons carrying out the test program and their associated training and competency in relation to the specific test program.

Content of IPTT programs

An IPTT program should include the following:

- A description of each interval to be tested.
- A description of the objectives of the testing program, and the procedures to be used in conducting, controlling and terminating the test, including:
  - a list of all flow and shut-in periods planned including proposed durations, and associated period objectives as presented in Table A1 of Appendix A; and

  - the operator's criteria for stabilized rate of flow for anticipated or marginal conditions.
- A description of all fluids used in conducting the test.
- The proposed fluid sampling program and sampling procedures. An operator should obtain samples of each fluid produced during a formation flow test for all wells in sufficient volumes and using techniques to permit the analysis required by the *Framework Regulations*. This should include submission of samples to the *Regulator.* As samples obtained during IPTT are generally pressurized samples, the operator should plan to accommodate for a 4 litre atmospheric (dead) oil sample in its program design. As a contingency, consideration should also be given to obtaining fluid samples before conducting testing operations via a wire line formation tester.
- Data gathering and reporting procedures.
- A description of the equipment to be used in the test program, including:
  - A diagram of the downhole test string with relevant pressure, temperature and H_2S ratings of equipment.
  - Specifics associated with all proposed downhole gauges (e.g., location in the string, sampling frequency, accuracy, resolution and provision for measurement verification).
  - A description of the proposed equipment pressure tests and calibration program of gauges used in the program.
- A description of the risks and associated measures put in place.
- A description of the procedures in place and the key steps for conducting the test, including any physical and environmental conditions or operating limits for conducting the program.
- A reference to applicable emergency response procedures and Contingency Plans in place.
- A description of the roles and responsibilities of key persons carrying out the test program and their associated training and competency in relation to the specific test program.

Decision to Test

Written confirmation of an operator's decision respecting testing should be provided to the *Regulator* as soon as the well has been evaluated upon reaching the total depth of the well. To allow for review and approval, final programs should be submitted as follows:

- Conventional cased-hole testing programs, including updated well and testing specifics, should be made at least five working days before start of testing operations.
- IPTT programs should be submitted before reaching the total depth of the well and conditionally approved pending submission of well specific details before the start of testing operations. When the final well specific details are provided, any deviations to the conditionally approved formation flow test program should be provided for review and acknowledgement by the *Regulator*.

Deviations from the Approved Formation Flow Test Program

Except for emergency response situations, in the event that it becomes necessary to deviate from details submitted as part of the program, information must be submitted to the *Regulator* for review and approval.

Sections 64 - 65 – Submission of Materials and Data

Samples and cores

64(1) An operator must ensure that all drill cutting and fluid samples and cores collected as part of the field data acquisition program referred to in section 13 and the well data acquisition program referred to in section 18 are
(a) stored in durable containers that are correctly labelled for identification;
(b) transported and stored in a manner that prevents any loss or deterioration; and
(c) delivered to the Board within 60 days after the day on which the well is abandoned, suspended or completed, unless the analyses are ongoing, in which case the samples and cores, or any remaining parts, are to be delivered to the Board on completion of the analyses.

Remaining conventional core

(2) An operator must 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 delivered to the Board.

Remaining sidewall core

(3) The operator must ensure that, after any samples necessary for analysis or for research or academic studies have been removed from a sidewall core, the remaining core is delivered to the Board.

Notice before disposal

65 Before disposing of any drill cutting or fluid samples, cores or evaluation data, an operator must ensure that the Board is notified in writing and given an opportunity to request delivery of the samples, cores or data.

Refer to the *Data Acquisition Guideline.*

LOCATION OF WELLS

Section 66 – Depth Measurements

66 An operator must ensure that no record is made of any depth in a well unless the depth is measured from the rotary table of the drilling rig.

- All well depths, SF (or mudline, if different from the normal SF, e.g., excavated drill centre) depth, hole depths, casing depths and other depths should be in reference to RT. This should include driller's depths, wire line logger's depths, MD and TVD.
- The distance from the RT to SF should be accurately measured to serve as the datum for all subsequent well depth measurements. The distance to the casing flange should also be recorded (i.e., RT to casing flange).
- All depths should be reported in metres and should be stated as:
  - mRT (MD) for metres from RT
  - mRT (TVD) for metres from RT
- For well operations from a floating installation, the RT-SF elevation should be corrected to 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 available to the driller at all times.
- Operators should use accurate and reliable wire line log data to properly correlate the perforation of intervals, setting of packers and any other downhole operation requiring accurate depth control.

Section 67 – Directional and Deviation Surveys

67 An operator must ensure that
(a) directional and deviation surveys are taken at intervals that allow the position of the well-bore to be accurately known during drilling;
(b) the directional and deviation surveys are adequate to permit the management, in relation to the well-bore, of identified geohazards, the intersection of the geological targets for the well and the intersection of the well-bore in the event that a relief well is required; and
(c) except in the case of a relief well, every well is drilled in compliance with internationally recognized well-bore collision avoidance practices and procedures and in a manner that does not intersect an existing well.

If several wells are drilled from a single location, or from locations near 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 well-bore collision avoidance policies and procedures. In this regard, MWD and gyroscopic data may be required to allow the position of the well-bore to be accurately determined to prevent it from intersecting an existing well.

WELL INTEGRITY

Section 68 – Well Control

68 (1) An operator must ensure that adequate procedures, materials and equipment are in place and used throughout the life cycle of the well to prevent the loss of well control.

Reliable well control equipment

(2) The equipment referred to in subsection (1) must include reliable well control equipment to detect and control kicks, prevent blowouts and safely conduct all well operations.

Shallow hazards

(3) During well operations conducted without a riser, the operator must ensure that measures are implemented to reduce the risk of shallow hazards while drilling.

Surface casing

(4) The operator must ensure that the surface casing of the well is installed to a sufficient depth, and in a competent formation, to establish well control for the continuation of the drilling operations.

Blowout preventer and barrier envelopes

(5) After the surface casing has been installed and cemented, the operator must ensure that
(a) a blowout preventer is installed before the casing shoe is drilled out; and
(b) there are at least two independent barrier envelopes — each of which is to be verified by the operator — in place throughout the life cycle of the well.

Barrier envelope failure

(6) If there is a failure in a barrier envelope, the operator must ensure that no well operation, other than one that is intended to replace or restore the barrier envelope, takes place until the barrier envelope is replaced or restored.

Replacement or restoration of barrier envelope

(7) The operator must ensure that
(a) the barrier envelope is replaced or restored as soon as the circumstances permit;
(b) every effort is made for the replacement or restoration to conform to the original design specifications; and
(c) the barrier envelope is verified after its replacement or restoration.

Drilling fluid column

(8) The operator must ensure that, during well operations, one of the two barrier envelopes is the drilling fluid column, except when drilling under-balanced or if, when a completion or test string is run, the other barrier envelope has already been installed downhole and tested.

Pressure control equipment

(9) The operator must ensure that all pressure control equipment associated with well operations is pressure-tested on installation and as often as necessary to ensure its continued safe operation.

Corrective measures

(10) If well control is lost or if safety, the protection of the environment or resource conservation is at risk, the operator must ensure that any necessary corrective measures are taken without delay.

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a. General

- Refer to the requirements and associated guidance for safety and environmental protection, physical and environmental conditions, hazardous and non-hazardous areas, ventilation, ignition prevention, electrical systems, control and monitoring systems, emergency shutdown systems, pressure systems, mechanical equipment, materials handling equipment, drilling risers, well tubulars, trees and wellheads as provided in sections 98, 104, 106, 108, 110, 111, 113, 114, 115, 122, 123, 124, 125, 133, 135, 136, 137, 164, 166 and 169 of the *Framework Regulations*.
- Refer to requirements and associated guidance for operations and maintenance of these systems under sections 73, 153, 155, 156, 157 and 158 of the *Framework Regulations*.
- Refer to the definition of “barrier element” and “barrier envelope” in section 1 of the *Framework Regulations*.

b. Barrier Envelopes

- With respect to subsection 68(5) of the *Framework Regulations*, a well barrier analysis should be conducted for each well operation, and for each phase of each well operation, to the extent appropriate, clearly outlining the primary and secondary well barrier envelopes. *NORSOK D-010 Well integrity in drilling and well operations* provides guidance in this regard and should be used in developing appropriate well barrier policies, procedures and work instructions for all types of well operations. 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 flow.
- With respect to subsections 68(6) and (7) of the *Framework Regulations*, making the well safe prior to commencing replacement or restoration is appropriate. Furthermore, depending on the circumstances and risk assessments, there could be rationale to conduct other activities prior to immediately rectifying the failure.

c. Procedures and Equipment

- With respect to subsections 68(1) and (3) of the *Framework Regulations*, refer to the requirements and associated guidance for safe operations provided under section 73 of the *Framework Regulations*.
- With respect to subsections 68(1), (2) and (3) of the *Framework Regulations*, equipment should be designed, constructed, operated and maintained to provide the necessary safety and environmental functions required during any normal and foreseeable situation or event and so that it functions effectively in all foreseeable physical and environmental conditions in which it may be expected to operate.
- The following documents should be considered:
  - *NORSOK D-001 Drilling Facilities*
  - *NORSOK D-002 Well Intervention Equipment*
  - *NORSOK D-010 Well integrity in drilling and well operations*
  - *API Std 53 Well Control Equipment Systems for Drilling Wells*
  - *API Std 64 Diverter Equipment Systems* (for specifications, maintenance and testing)
  - *ISO 13354 Petroleum and Natural Gas Industries – Drilling and production equipment – Shallow Gas Diverter Equipment* (for operations)
  - *API RP 16ST Coiled Tubing Well Control Equipment Systems*
  - *API Std 17G Design and Manufacture of Subsea Well Intervention Equipment*
  - *API RP 17G5 Subsea Intervention Workover Control Systems*
  - *SPE 20430 Mud Gas Separator Sizing and Evaluation*
  - Classification society rules with respect to well control equipment
- In addition to guidance provided *in API Std 53*, *NORSOK-D001* and *NORSOK D-010* for BOP and Control Systems, the following guidance is provided:
  - The fail-safe valves should be protected from falling objects by being located as close to the body of the BOP as practicable.
  - An effective means of clearing trapped gas from the BOP should be in place.
- With respect to pressure control equipment, the following should be considered:
  - BOPs and other well pressure control equipment should be function tested at least once per week.
  - Choke and kill lines on a subsea BOP should be flushed on a regular basis to ensure no blockages have occurred. Flushing is recommended twice daily when operations permit. Fluid composition (i.e., glycol concentrations) should be selected based on the weather conditions and should consider extreme cold conditions if forecasted.

  - The choke and kill system should be sized such that pressure losses do not limit or impede well control operations. Fluid composition (e.g., glycol concentrations) should be selected based on the physical and environmental conditions and consider extreme cold conditions, if forecasted.
  - Every valve on the choke manifold should be clearly marked to indicate its normal position.
  - 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 and 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.
  - A single overboard line may be used for the discharge of well fluids overboard from the choke manifold, when this configuration can be shown to provide at least the same level of safety.
- Additional considerations for subsea well operations:
  - BOPs used on floating drilling installations should have two sets of shear rams spaced at a distance such that, when possible, if a non-shearable is across one set of rams it does not result in damage to the other ram in the event it needs to be activated.
  - 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 (part of the drilling riser). 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.
  - The risk assessment should review and assess the appropriateness of the following:
    - Executive actions associated with automatic functions for deadman, auto-shear, acoustic and emergency shutdown.
    - The location of any local or remote control panels to ensure that the controls have adequate redundancy and protection and are quickly accessible by persons supervising well operations. 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 in a suitably protected location that is easily and quickly accessible.
    - In the case of a subsea BOP, both valves installed on each choke and kill outlet should be remotely operated fail-safe valves.
    - The subsea BOP stacks should have either one or more of the following installed based on the risk assessment: autoshear system, deadman system or acoustic BOP control system. The backup system should be independent of the main BOP system (e.g., separate hydraulic system). For DP vessels and deepwater systems, consideration should be given to installing two back-up systems along with ROV intervention capability. Operators using DP vessels should also consider the need to implement an acoustic BOP control system and to equip subsea BOP stacks with two shear rams.

- The autoshear, deadman, acoustic systems and all ROV intervention functions on the BOP stack should be function tested in addition to and during the standard stump test.
- 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, should also to be tested.
- Following the initial subsea test of these systems, tests should 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.

d. Drilling Fluid

- With respect to subsection 68(8) of the *Framework Regulations*, the following interpretations are made with respect to drilling fluid:

  - **Enhanced Mineral Oil-Based Fluid (EMOBF)** - means a non-aqueous drilling fluid in which the continuous phase is a highly-purified petroleum distillate with a total polycyclic aromatic hydrocarbon concentration of less than 10 mg/kg, is relatively non-toxic in marine environments and has the potential to biodegrade under aerobic conditions.
  - **Non-Aqueous Fluid (NAF)** - means a drilling fluid in which the continuous phase is a non-aqueous fluid in which weighting agents, additives and typically some water are emulsified or dissolved.
  - **Oil-Based Fluid (OBF)** - means a NAF in which the continuous phase is a product obtained from petroleum distillation (e.g., diesel oil or mineral oil).
  - **Synthetic-Based Fluid (SBF)** - means a NAF in which the continuous phase is composed of one or more fluids produced by the reaction of specific purified chemical feedstock, rather than through physical separation processes such as fractionation, distillation and minor chemical reactions such as cracking and hydro processing. It should have a total polycyclic aromatic hydrocarbon concentration of less than 10 mg/kg, be relatively non-toxic in marine environments and have the potential to biodegrade under aerobic conditions.
  - **Water-Based Fluid (WBF)** – means a drilling fluid in which the continuous phase is water in which the weighting agents and additives are emulsified or dissolved.

- When it is technically reasonable, WBF should be used to drill a well.
- NAF (e.g. SBF, OBF or EMOBF) may be used to drill a well if it is demonstrated to the *Regulator* that the likelihood of successfully drilling a well is significantly better than drilling with WBF (e.g., requirements for enhanced lubricity, gas hydrate mitigation).
- The use of OBF will be approved only in exceptional circumstances.
- Unless the well approval issued pursuant to section 17 of the *Framework Regulations* provides for drilling with losses or MPD, the well should be kept full with a column of drilling fluid of sufficient density to overbalance formation pressure at all times, taking into account swab pressures, trip margins and riser margins. Operators should ensure that drilling ceases

and remedial measures are undertaken if the drilling fluid does not provide an effective barrier against flow.

- Consideration should be given to using a pressurized drilling fluid balance in gas-prone areas. Drilling fluid properties should be measured by fully maintained equipment regularly in accordance with the following:
  - *API Spec 13A Specification of Drilling Fluids Materials*
  - *API RP 13B-1 Field Testing Water-Based Drilling Fluids*
  - *API RP 13B-2 Field Testing Oil-Based Drilling Fluids*

e. Pressure Testing of Drilling BOPs

- With respect to subsection 68(9) of the *Framework Regulations*, the following guidance is provided for pressure testing of BOPs in addition to the guidance provided in *API Std 53* and *NORSOK D-010*:
  - Pressure testing of all components of the BOP (except blind shear rams) should be conducted 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. When well conditions or other hazards preclude pressure testing within the 14 day timeframe, the test should be delayed by no more than 7 days.
  - 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 should be conducted immediately prior to running the BOP.
  - Blind shear rams should be pressure tested at least once every 30 days.
  - Digital pressure testing data is an acceptable form of record regarding pressure testing of BOPs. If digital data cannot be obtained, records from a calibrated chart recorder can be used.

f. Pressure Testing of Other Pressure Control Equipment

With respect to subsection 68(9) of the *Framework Regulations*, the following guidance is provided for pressure testing of other pressure control equipment (e.g., used for completion, intervention, formation flow testing) in addition to the guidance provided in *NORSOK D-010*, digital pressure testing data is an acceptable form of record regarding pressure testing of pressure control equipment. If digital data cannot be obtained, records from a calibrated chart recorder can be used.

Section 69 – Casing and Wellhead System

69 (1) An operator must ensure that a casing and wellhead system is designed, taking into account the wellhead's fatigue life, so that, throughout the life cycle of the well,

(a) the well can be drilled safely, targeted formations can be evaluated and developed and waste can be prevented;
(b) the maximum conditions, forces and stresses to which the casing and wellhead system may be subjected are withstood; and
(c) the integrity of gas hydrate and permafrost zones is protected.

Barrier analysis

(2) The operator must ensure that, during the design of the casing and wellhead system, if the annulus is to be used for fluid production or injection, a barrier analysis is conducted to confirm that two barrier envelopes can be maintained in place throughout the life cycle of the well.

Casing depth

(3) The operator must ensure that each casing is installed at a depth that provides for adequate kick tolerance and safe well control.

Wellhead fatigue life

(4) The operator must ensure that well operations do not continue beyond the wellhead's fatigue life.

Cement slurry

(5) The operator must ensure that the cement slurry is designed and installed so that, throughout the life cycle of the well,
(a) the movement of formation fluids is prevented and, when required for safety, resource evaluation or waste prevention, 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 minimized; and
(d) the integrity of gas hydrate and permafrost zones is protected.

Cement integrity and placement

(6) The operator must ensure that the cement integrity and placement are verified, subject to subsection (7), through pressure-testing and, if the cement is a common barrier element of the two barrier envelopes or if confirmation of zonal isolation is required, also through logging.

Other methods of verification

(7) The cement integrity and placement may be verified using other methods if the operator demonstrates that those methods provide a level of verification that is equivalent that is equivalent to those referred to in subsection (6).

Cement design and slurry analysis

(8) The operator must ensure that the cement design is subjected to comprehensive laboratory testing and pre-cementing quality control, under all foreseeable conditions that could have an impact on cementing, so that the cement provides the expected isolation and can be efficiently installed.

Waiting on cement time

(9) The operator must ensure that, after cementing any casing or casing liner and before drilling out the casing shoe, the cement reaches the minimum compressive strength sufficient to support the casing and provide zonal isolation.

Casing pressure testing

(10) The operator must ensure that, after any casing is installed and cemented and before the casing shoe is drilled out, the casing is pressure-tested to the value required to confirm its integrity for maximum anticipated operating pressure throughout the life cycle of the well.

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a. Casing

- The casing should 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 minimum design factors used in the design of well casing should be in accordance with *NORSOK D-010 Well integrity in drilling and well operations*.
- Alternative casing methods such as LRFD will be considered as part of the application for an OA under section 8 of the *Framework Regulations.* It is noted that 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 should be explained and justified. All details regarding casing properties, risk analysis and quality control should be provided if this is the method selected to be used.
- With respect to paragraph 69(1)(b) of the *Framework Regulations*, the casing and wellhead system design should consider the loads imposed by the drilling riser, BOP system, tensioning systems, etc., and the requirements and associated guidance for physical and environmental conditions under section 104 of the *Framework Regulations*. In addition, consideration should be given to ensuring the casing and wellhead are suitably designed to accommodate a capping stack. For a jack-up installation, the casing and wellhead system should be designed in consideration of the wave and wind loads, taking into account tensioning systems. For platform wells, the structural analysis of the conductor casing should consider buckling loads.
- Casing design should also consider the requirements of *ANSI/NACE MR-0175/ISO 15156 Petroleum and natural gas industries – Materials for use in H_2S-containing environments in oil and gas production.*

- The requirements and associated guidance under section 73 of the *Framework Regulations* should be referred to for safe operations practices and procedures.
- The following documents should be considered:
  - *NORSOK D-010 Well integrity in drilling and well operations*
  - *API Technical Report 5C3 Calculating Performance Properties of Pipe Used as Casing and Tubing*
  - For sour gas wells, refer to *NORSOK D-010* and the *Energy Safety Canada's Industry Recommended Practice Volume 1 - Critical Sour Drilling* and other associated industry recommended practices
  - For HPHT wells, reference to *Energy Institute Model Code of Practice: Part 17, Volume 1: High pressure and high temperature well planning*
- Any casing installed in a well should be new pipe.
- Any casing or liner string installed should consider the use of centralizers 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.
- When designing the well and casing, the operator should outline the objectives for the design. The design should consider pore pressure and fracture gradients, kick tolerance, expected lithology, ability to evaluate, prevention of waste, well-bore instability, presence of potable water zones, faults, lost circulation zones and any other drilling hazards.
- Casing hanger latching mechanisms or lock down mechanisms should be engaged when the casing is installed in the subsea wellhead.

b. Cement

- 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. The program should include:
  - a description of mandatory cementing practices, recommended practices and operational guidelines;
  - the policies and procedures on the design, placement and validation programs inclusive of contingencies that should be followed if there are issues experienced;
  - the policies and procedures that clearly define lost returns, partial returns, full returns and cement volume margin and the actions to be taken when such events occur;
  - the policies and procedures that clearly define the density hierarchy between drilling fluid and spacers for the cementing program;
  - the policies and procedures that clearly define the selection, types and number of centralizers to ensure the minimum stand-off is achieved;
  - requirements for reviewing the integrity of well barriers at safety-critical milestones, such as before removal of the BOP and riser from the wellhead, before re-entry of a well after suspension, before removal of any well barrier, etc.; and
  - the 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, including clear clear criteria that will indicate success, and circumstances that would require additional evaluation.

- The following documents should be considered:
  - *NORSOK D-010 Well integrity in drilling and well operations*
  - *API Spec 10A Cements and Materials for Well Cementing*
  - *API RP 65-1 Cementing Shallow Water Flow Zones in Deepwater Wells*
  - *API Std 65-2 Isolating Potential Flow Zones During Well Construction*
- The conductor casing and permafrost casing, if required, should be cemented from the shoe of the casing to the SF (or mudline).
- The surface casing should be cemented to the SF (or mudline).
- 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.
- When practicable, the full length of every casing liner should be cemented.
- 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.
- 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.

c. Pressure Testing

- Refer to guidance provided in *NORSOK D-010 Well integrity in drilling and well operations.*
- Before displacement of drilling fluid from the well-bore, the operator should verify that:
  - Two independent verified barriers, including one mechanical barrier, are in place for each flow path (i.e., casing and annulus).
  - 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 before setting the subsequent casing barrier. A negative pressure test should be performed before 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 is more than the highest estimated integrity of the casing shoes below the barrier.
  - Before displacing a well to an under-balanced fluid, the well should be displaced in stages, continuously monitoring for flow and be prepared to shut in and isolate the well at any indication of a failed barrier.
- Casing wear should be considered in the design and operational phases. If a casing string has the potential to be subject to excessive casing wear by pipe movement due to an extended duration of through-casing operations or predicted high side forces, specific plans should be put in place to ensure its continued integrity as a barrier during drilling operations.

Section 70 – Formation Leak-Off or Integrity Test

70 (1) An operator must ensure that a formation leak-off test or a formation integrity test is conducted
(a) before drilling more than 10 m of new formation below the shoe of any casing other than the conductor casing; and
(b) before drilling more than 10 m when sidetracking from the previous casing string.

Pressure

(2) The formation leak-off test or formation integrity test must be conducted at a pressure that allows for safe drilling to the next casing depth and for the adequacy of the cement at the level of the shoe to be verified before drilling ahead.

- FLOTs or FITs should be executed in accordance with *NORSOK D-010 Well integrity in drilling and well operations* or other accepted industry standards.
- For wells in which there is a good understanding of formations and pressures as a result of offset well data, a FIT is an appropriate means for verifying formation integrity. This is usually the case with development wells.
- For wells in which there is greater uncertainty regarding formations and pressures, a FLOT is a more appropriate test to be undertaken. This is usually the case with exploration and delineation wells.

Section 71 – Completion, Testing and Operation of Development Wells

71 (1) The operator of a development well must ensure that
(a) the well is completed, tested and operated in a safe manner that allows for maximum recovery of petroleum without waste or pollution throughout the life cycle of the well;
(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) if applicable, the production of sand, carbonate or other solids is controlled and does not create a safety hazard or cause waste;
(d) the setting depth of each packer is as deep as possible and is such that any leak through the production casing below the packer will be contained by the barrier envelope outside the casing;
(e) the formation and any annulus seal can withstand the pressures and temperatures expected throughout the life cycle of the well;
(f) if practicable, any mechanical well condition that may have an adverse effect on the 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 of petroleum from any of those pools, the well is operated as a single pool well or as a segregated multi-pool well;
(i) during completion operations and before the removal of pressure control equipment and handover for operations, all barrier elements are tested to the maximum pressure to which they are anticipated to be subjected and, if possible, pressure testing is in the direction of flow; and
(j) following any workover or intervention, any affected barrier elements are pressure-tested.

Segregated multi-pool well

(2) If the development well is a segregated multi-pool well, the operator must also ensure that
(a) after the well is completed, segregation within and outside the well casing is verified; and
(b) if there is reason to doubt that segregation is being maintained, a segregation test is conducted as soon as the circumstances permit.

Definition of multi-pool well

(3) In this section, multi-pool well means a well that is completed in more than one pool.

- Refer to the requirements and associated guidance for pressure control equipment, production tubing, SSVs, and wellhead and tree equipment under sections 68, 72, 165 and 166 of the *Framework Regulations*, respectively.
- Any commitments or conditions of the *Development Plan* for production wells should be considered, especially in relation to waste.
- Completion technologies and methods that have been proven to be reliable for the expected life of the well should be accounted for at the design stage and include consideration of plug and abandonment requirements. This should include consideration of technologies that enable monitoring of the various annuli, including in subsea wells. If a new technology is planned, refer to the requirements and associated guidance under section 103 of the *Framework Regulations*.
- The zone characteristics and the type of well completion or workover contemplated should be considered.
- Completion programs need to assess the ability to effectively isolate zones during plug and abandonment, including for open hole completions.
- A program should be in place for ensuring that the well integrity of production wells is monitored and maintained throughout the life of the well. Guidance on monitoring and classification of well impairments is provided in the *Norwegian Oil and Gas Association Recommended Guidelines for Well Integrity – No. 117*. All equipment used in the completions should be protected from corrosion or wear/degradation to prevent loss of strength or function, and should meet the requirements of *ANSI/NACE MR-0175/ISO 15156 Petroleum*

and natural gas industries – Materials for use in H_2S-containing environments in oil and gas production. To ensure safety and resource conservation, an annular well pressure monitoring and evaluation program should be in place. Guidance is provided in the *API RP 90-1 Recommended Practice for Annular Casing Pressure Management for Offshore Wells*.

- Before production from a specific zone, all zones should be hydraulically isolated from any other productive zone. Should zonal isolation not be achieved, a demonstration of why the well should be allowed to produce should be provided to the *Regulator* before any further production occurs. The operator should correct or change any mechanical well condition if practical to maximize ultimate recovery.
- Refer to the requirements and associated guidance for commingled production under section 80 of the *Framework Regulations*.
- 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.
- The production packer should be installed at a depth that is within the cemented interval of the selected casing section and as close as practicable to the interval being completed.
- Negative pressure or inflow testing should be conducted when the well is completed and periodically throughout the life of the well, as needed.
- The following documents should be considered:
    - *NORSOK D-010 Well integrity in drilling and well operations*
    - *Energy Safety Canada Industry Recommended Practice Volume 2, Completing and Servicing Critical Sour Wells*
    - *Energy Safety Canada Industry Recommended Practice Volume 14, Non Water-Based Drilling Fluids*
    - For HPHT wells, reference should be made to *Energy Institute Model Code of Practice: Part 17, Volume 3: High pressure and high temperature well completions*

Section 72 – Production Tubing

72 An operator must ensure that the production tubing used in a well is designed and maintained to be compatible with the fluids to which it will be exposed, to withstand the maximum conditions, forces and stresses to which it may be subjected and to maximize recovery of petroleum from the pool.

- All tubing and associated equipment should be designed and operated 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.

- All tubing and associated equipment should be protected from corrosion, wear and degradation to prevent loss of strength or function. This should include consideration of factors such as where the completion is landed out (i.e., in oil, gas or water leg), the well initiation approach, impact from potential extended shut-in and the requirements of *ANSI/NACE MR-0175/ISO 15156 Petroleum and natural gas industries – Materials for use in* H_2S*-containing environments in oil and gas production*.
- All tubing should be sized to maximize recovery in relation to the pressures and fluids to be produced or injected.
- Standards to be considered:
  - *NORSOK D-010 Well integrity in drilling and well operations.*
  - *API Technical Report 5C3 Calculating Performance Properties of Pipe Used as Casing or Tubing.*

Section 73 – Safe Operations and Production

73 An operator must ensure that equipment and procedures are in place to recognize and control normal and abnormal operating conditions, for the purposes of allowing for safe and controlled well operations and production and of preventing pollution.

a. General – System Operating Procedures

System operating procedures (including those for normal, temporary or emergency operations) should be developed that takes into consideration the following:

- Refer to the requirements and associated guidance for:
  - "Control of documents", "operations and maintenance procedures", "organizational structure and roles, responsibilities and authorities" and "training and competency assurance" under Part 3 of the *Framework Regulations*.
  - Procedures under sections 41, 48 and 49 of the *Framework Regulations*.
  - Contingency plans, emergency response plans and drills and exercises under section 11 of the *Framework Regulations*.
  - Operations manuals under section 157 of the *Framework Regulations*.
- In general, and in addition to the content for "documents" and "operating and maintenance procedures" under Part 3 of the *Framework Regulations*, system operating procedures should include:
  - The requirements for equipment that are described in the various sections of the *Framework Regulations* and *OHS Regulations* and should also consider associated guidance. If an operational step or procedure is required by a code or standard that is either referenced in the regulations or referenced as part of an application for an OA, this information should be documented as prescribed by that code or standard.

    - Any assumptions and measures associated with normal or emergency procedures that have been identified from any risk assessments completed. Refer to the requirements and associated guidance under sections 107 and 108of the *Framework Regulations*. This should also include any measures that will also reduce the potential risk of injury to persons.
    - Reference to operating or physical and environmental condition limitations for the equipment, the consequences of deviating from established limits, and steps required to correct or avoid a deviation from limits. Refer to the requirements and associated guidance under sections 105, 105, 106 and 156 of the *Framework Regulations*.
    - Reference to associated design, operation and maintenance standards.
    - Reference to associated equipment, inclusive of installed features for protection of safety and the environment.
    - Reference to Interdependent systems or equipment.
    - Reference to vendor data sheets, equipment data sheets, arrangement drawings and technical drawings, such as piping and instrumentation, electrical, process flow diagrams, etc.
- With respect to preventive measures, the automation of processes and the reduction of manual handling should be considered and applied if there is not a measurable increase in risk to do so.
- If remote monitoring, maintenance or control is being considered, refer to the requirements and associated guidance provided in sections 123, 124, 125 and 169 of the *Framework Regulations*.

b. General – Training and Competency

Refer to the requirements and associated guidance for the training and competency of persons under section 3 of the *Framework Regulations*. In addition to general training and competency requirements, the COP TQOP contains role specific training for persons in roles onboard drilling and production installations.

c. Specific Operating Procedures Applicable to Well and Production Operations

- **Manual Valves** - A system should be in place to ensure that all manual valves used in well or production operations in which an inadvertent or uncontrolled operation could result in a hazard to persons or the environment are secured and that their operation is only permitted under the work permit process[27]. The position and security of these valves should be checked routinely.
- **Inhibits** - All inhibits to executive actions or audible alarms should be recorded and authorized as part of the work permit process, communicated and measures should be taken, as appropriate, to ensure that risk remains at acceptable levels. Extended inhibits of executive actions or audible alarms should not be controlled via normal operational or work permit

[27] All critical valves should be locked or car-sealed and listed on a register. These devices should only be removed under the work permit system and replaced immediately after the work has been completed. Valves that may need to be operated in an emergency should be car-sealed for quick accessibility and following their operation, the car-seal should be re-applied.

procedures. Rather, the extended inhibits should be managed via appropriate and thorough management of change processes that include appropriate levels of risk analysis.

- **Venting, Depressurizing or Cleaning** – A system should be in place to ensure that the venting, depressurizing and cleaning of any equipment that contained hydrocarbons, flammable, toxic or other hazardous substances is done safely and in the manner and within the limits described in the Environmental Protection Plan as required by section 10 of the *Framework Regulations*.

d. Well Operations Procedures (Drilling, Completion, Workover, Servicing, Intervention, Plug and Abandonment Operations)

With respect to drilling and well operation procedures, guidance is provided in *NORSOK D-010 Well integrity in drilling and well operations* and *API RP 59 Recommended Practice for Well Control Operations.*

Policies and procedures should address at a minimum the following topics:

General Topic	Guidance
Well Trajectory	Refer to the requirements and associated guidance under section 67 of the *Framework Regulations*.
Casing Program	Refer to the requirements and associated guidance under section 69 of the *Framework Regulations*.
Kick Tolerance	Adequate kick tolerance should be in place at all times. Measures should be taken to ensure kick tolerance continues to be maintained in the event an abnormal pressure is encountered. Policies should address the following: • The minimum acceptable kick tolerance for drilling ahead should be identified. Kick tolerances to be maintained for development vs. exploration wells may differ. • Identify actions to be taken when minimum kick tolerance requirements are not met both in well design and well execution phases. • Kick tolerance management when mud weight, pore pressure and fracture pressure changes are encountered (i.e., kick tolerance should be revisited when changes are encountered). • For kick tolerance modelling purposes, unless the risk of gas in the next hole section is negligible, the kick fluid should be modelled as dry gas. The influx should be modeled as gas at the TD of the next section, in addition to any other depth necessary to assess the highest pressure case for the well.

General Topic	Guidance
	• Highest pore pressure predictions are to be used when there is minimal offset pressure data available for the well. • When dynamic calculations are used, the software should be approved by a well control specialist and users adequately trained in its use. • For multilateral well-bores that are not isolated from one another, consideration should be given to the highest case pressures and weak zones of each leg in conducting kick tolerance analysis.
Cementing Program	Refer to the requirements and associated guidance under section 69 of the *Framework Regulations*.
FLOT and FIT	Refer to the requirements and associated guidance under section 70 of the *Framework Regulations*.
Drilling Fluid	**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 drilling riser disconnected. In deepwater operations in which this is impractical, other risk-reducing measures should be in place such as spotting a weighted pill or installing a bridge plug with a storm valve below the wellhead before 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. Additional guidance on operational practices for drilling risers is provided in *API RP 16Q Design, Selection, Operation and Maintenance of Marine Drilling Riser Systems*. **Material Balance** When using OBF or SBF, a material balance should be maintained to track volumes of both base oil and drilling fluid discharged, retained, lost downhole or left in the hole. **Tripping Management** Particular attention should be paid to the drilling fluid system while tripping. Equipment and procedures should be in place to ensure that any losses or gains are promptly detected and that appropriate measures are taken to ensure that the drilling fluid is maintained as an effective barrier against flow. Swab/surge pressures should be modelled, tripping schedules should be developed and followed with respect to speeds to adequately maintain an overbalanced environment preventing kicks or loss of circulation during tripping operations. In the case of losses,

General Topic	Guidance
	operators are expected to take such steps as required to ensure that the loss of drilling fluid does not cause pollution. Refer also to the requirements and associated guidance under section 163 of the *Framework Regulations*.
Shallow Gas	For all programs involving the initial drilling of a well or series of wells (up to four) at a location without a riser and BOP installed, operators should establish procedures for encountering shallow gas and use of a diverter system. While all measures should be taken to prevent or reduce the risk of encountering shallow gas before a well is drilled, these procedures should be in place. In the case of subsea wells in which the conductor and surface hole is drilled riserless, at a minimum, the following should always be conducted: • The wind direction and current should always be known and preferred evacuation stations identified. • A shallow gas release drill should be held such that persons are clear on the actions to be taken. • Any activity that can produce a source of ignition (e.g., hot work) at an installation or on adjacent installations or vessels should be prohibited. • Any systems that are required to move off location quickly should be operational and protected to reduce the risk of ignition (e.g., mooring systems). • The fluid returns at the seabed should be monitored with an ROV or subsea camera for the purpose of identifying any well flow or bubbles. • A volume of weighted drilling fluid should be maintained as a contingency to kill the well. • The conductor/surface hole should be displaced to heavy fluid before pulling out of the hole unless drilling in water depths greater than 500m.
Well Control	**Monitoring of Parameters Critical to Well Operations** Consistent with *Good Oilfield Practices*, all pressure detection parameters including the rate of penetration, drilling exponent, shale density, cuttings size and shape, drilling fluid (e.g., mud) gas levels, torque, drag, fill, temperature and any other pertinent parameter should be monitored during well operations to detect any transition zone from normal to abnormal pressure and to detect any kicks. The use of LWD or other tools may also greatly assist in abnormal pressure detection. If necessary, wire line logs should be acquired if needed to confirm formation pressures. Dedicated persons competent to measure,

General Topic	Guidance
	monitor, record and report on parameters critical to pressure and kick detection, should be available at all times in the mudlogging unit and in other locations dependent on the risk. For higher risk wells, this may also involve real time monitoring from additional resources at a shore based facility. Direct and reliable communications among mudloggers, the driller and other key persons should be available at all times. Parameters to be monitored from the mudlogging unit should include 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. **Maintaining an Overbalance** Unless the well approval issued pursuant to section 17 of the *Framework Regulations* provides for drilling with losses or MPD, the well should be 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. Drilling should cease and remedial measures be undertaken if the drilling fluid does not provide an effective barrier against flow. When surface back pressure managed pressure operations are conducted, the equivalent mud weight fluid column should overbalance the formation pressure at all times. **Well Control** The procedures for well control should include the roles and responsibilities of all persons involved with well operations, monitoring and detection methods, shutting in the well and the well kill approach for various scenarios. Procedures should address escalating well control events and not be limited to initial influx shut-in (e.g., escalating kicks and blowouts). All persons involved with well operations should be familiar with the procedures, participate in routine drills and also know the steps to take when well control is lost. Persons should understand when to activate shear rams, disconnect or activate emergency shutdown systems. Persons should have well control training as described in the COP TQOP. Persons should also have ready access to well control experts with advanced well control training. Additional guidance is provided in *IOGP Report 485 Standards and guidelines for well integrity and well control.* Refer to the requirements and associated guidance under section 68 of the *Framework Regulations*. The procedures for loss of well control should include criteria for when to activate shear rams, conduct an emergency disconnect, activate

General Topic	Guidance
	emergency shutdown systems and move off location, if possible. Procedures should address uncontrolled underground flow of fluids from one formation into another. Procedures should also address the steps necessary to regain well control, such as drilling a relief well or employing subsea capping and containment. It should always be possible to regain well control at all times by direct intervention or by drilling a relief well.
Well Barrier	With respect to any operation on a well, a well barrier analysis should be conducted for each well operation, and for each phase of each well operation to the extent appropriate. Persons involved in the work or activity should be made 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) to provide the necessary clarity to persons involved in the work or activity. Persons in the field should also be provided with instructions to follow in the event that a primary or secondary well barrier element fails. Procedures for the loss of well barriers should consider the following: • Well barrier elements should be identified for all phases of the well's life cycle and there should be clear understanding of which well barrier element failures constitute a failure to a well barrier. • If a barrier fails, no activities should take place in the well other than those intended to restore the barrier. Specific guidance is provided in *NORSOK D-010, Well Integrity in drilling and well operations*. Refer also to the requirements and associated guidance under section 68 of the *Framework Regulations*.
Well Kill Readiness	Information on all non-shearable components in the work string should be available to the driller at all times and used with the BOP Space-Out Diagram. Refer to the requirements and associated guidance under section 68 of the *Framework Regulations*.
Lost Circulation	Refer to the requirements and associated guidance under section 68 of the *Framework Regulations*.
Well Shut-In	Refer to the requirements and associated guidance under section 68 of the *Framework Regulations*.

General Topic	Guidance
Hang-off and Emergency Disconnect	Refer to the requirements and associated guidance under sections 68, 148 and 164 of the *Framework Regulations*. These procedures should include any situation or event with the drilling riser that could give rise to the inability to actuate the BOP stack via the BOP hydraulic or multiplex control system. In addition, re-entry procedures should be developed.
Source Control	Refer to the requirements under section 11 of the *Framework Regulations* and associated guidance provided in the *Contingency Plan Guideline*.
Well Intervention	Refer to the requirements and associated guidance under section 68 of the *Framework Regulations* with respect to coiled tubing or wire line operations. Additional guidance with respect to coiled tubing operations is also provided in *API RP 5C7 Recommended Practice for Coiled Tubing Operations in Oil and Gas Well Services* and *API RP 16ST, Coiled Tubing Well Control Equipment Systems.*
Formation Flow Testing	Refer to the requirements and associated guidance in sections 63 and 167 of the *Framework Regulations*. In addition, the following should be included: • If the capability exists, the riser should be circulated during formation flow testing operations to monitor volumes to detect any influx. • The initial flow or circulation of formation fluids to surface should only occur during daylight hours. Subsequent flows associated with the same test should occur during nighttime hours only when adequate lighting is provided over the testing area, which should include the area around the flare boom and the ocean surface.
Well Suspension and Abandonment	Refer to the requirements and associated guidance in sections 90 - 93 of the *Framework Regulations*.
MPD/Under-balanced Drilling (if applicable)	If this is planned to be undertaken during drilling of the well, it is expected that all operational practices affected are updated to reflect this activity and include additional measures and considerations, specifically those related to kick detection and prevention. Additional guidance is provided in *NORSOK D-010 Well integrity in drilling and well operations*.
Deepwater Wells (if applicable)	If any well operations are planned to be undertaken in deep water, it is expected that all operational practices affected are updated to reflect this activity and include additional measures and considerations, specifically those related to kick detection and prevention. The *IADC*

General Topic	Guidance
	Deepwater Well Control Guidelines provides guidance for 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.
HPHT (if applicable)	If conducting any well operations on a well with potential HPHT, it is expected that all operational practices affected are updated to reflect this risk and include additional measures and considerations, specifically those related to kick detection and prevention. Additional guidance is as follows: • *Energy Institute Model Code of Practice: Part 17, Volume 1: High pressure and high temperature well planning* • *Energy Institute Model Code of Practice: Part 17, Volume 2: Well control during the drilling and testing of high pressure, high temperature offshore wells* • *Energy Institute Model Code of Practice: Part 17, Volume 3: High pressure and high temperature well completions*

NOTE:

- *For wells that are generally considered more complex (*e.g.*, HPHT, deepwater) or with an increased risk profile, the Regulator expects that additional measures/considerations are taken in addressing these topics, specifically those related to kick detection and prevention. These additional measures should be clearly articulated in documentation provided in support of an application for an OA. Higher risk wells should include additional measures such as increased oversight of pore pressure prediction and monitoring, increased planning and communication of operating and emergency procedures, additional drills, increased supervision, etc*.

e. Production Operating Procedures

With respect to production operations, operating procedures should also address the following:

- Initial startup of a new installation, systems or equipment
- Normal operations
- Temporary operations
- Upset/abnormal conditions
- Emergency shutdown, including identification of conditions that require shutdown
- Controlled shutdown
- Start-up following an emergency or controlled shutdown
- Black start
- Procedures for the isolation of equipment and the preparations for intrusive maintenance

With respect to production operations, the following specific guidance should be referred to:

- *NORSOK D-010 Well integrity in drilling and well operations.*
- *API RP 90-1 Recommended Practice for Annular Casing Pressure Management for Offshore Wells.*
- *API RP 19GLHB Gas Lift Handbook* contains guidance for the design, operation and maintenance of gas-lift.

MEASUREMENTS

Sections 74 – 76 – Flow, Volume and Quantity and Allocation

Flow and volume

74 (1) Subject to subsection (2), an operator must ensure that the following are measured:
(a) the rate of flow and the volume of the fluid that is produced from each well;
(b) the rate of flow and the volume of the fluid or waste material that is injected into each well; and
(c) the volume of the fluid that is produced from each well that is used, flared, vented, burned or otherwise disposed of.

Alternate measurements

(2) Alternate measurements may be conducted if approved by the Board under section 14.

Method

(3) The operator must ensure that all measurements are conducted using the flow system, flow calculation procedure and flow allocation procedure approved under subsection 14(2).

Allocation of group production

75 An operator must ensure that group production of oil, gas and water from wells and the volume of fluids injected into those wells are allocated on a pro rata basis using the flow system, flow calculation procedure and flow allocation procedure approved under subsection 14(2).

Allocation over multiple pools or zones

76(1) If a well is completed over multiple pools or zones, the operator must ensure that the production of oil, gas and water from the well and the volume of fluids injected into the well are allocated on a pro rata basis to the pools or zones using the flow allocation procedure approved under subsection 14(2).

Proration tests

(2) The operator must ensure that sufficient proration tests are conducted to measure the rates at which fluids are produced from the well to ensure that the allocation of oil, gas and water production to the pools and zones as a result of the flow allocation procedure is accurate.

Refer to guidance provided in the *Measurement Guideline*. In addition, in NL, the measurements for flow and volume from wells should follow the *Monthly Production Reporting Guideline.*

Section 77 – Testing and Maintenance

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77 (1) An operator must ensure that
(a) meters and other associated components of the flow system are calibrated and maintained to ensure their accuracy;
(b) the equipment used to calibrate the flow system is calibrated in accordance with good measurement practices; and
(c) 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 in progress.

Notice

(2) The operator must ensure that a conservation officer is notified, as soon as the circumstances permit, of any modification to or 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.

- With respect to subsection 77(2) of the *Framework Regulations*, refer to guidance for the reporting of events in the *Incident Reporting and Investigation Guideline.*
- Refer to guidance provided in the *Measurement Guideline.*

Section 78 – Calibration

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78 An operator must ensure that

(a) a conservation officer is notified of the calibration of any transfer meter prover or master meter used in conjunction with a transfer meter at least 30 days before the day on which it is calibrated or as agreed to in writing by the Chief Conservation Officer; and
(b) following completion of the calibration, a copy of the calibration certificate is submitted to the Chief Conservation Officer as soon as the circumstances permit.

Refer to guidance provided in the *Measurement Guideline.*

PRODUCTION CONSERVATION

Section 79 – Resource Management

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79 An operator must, in respect of the recovery of petroleum, ensure that
(a) recovery from a pool or zone is maximized in accordance with good oilfield practices;
(b) wells are located and operated to provide for maximum recovery from a pool or zone; and
(c) if there is reason to believe that infill drilling or the implementation of an enhanced recovery plan might result in increased recovery from a pool or field, studies on those methods are conducted and submitted to the Board.

Maximizing Recovery

With respect to paragraph 79(a) of the *Framework Regulations*, refer to the following:

- The prevention of “waste” as defined in the *Accord Acts* is an essential part of petroleum development.
- Refer to definition of *Good Oilfield Practices* in Section 2.0 of this Guideline.
- Operators should be aware that to maximize recovery from a pool or zone, production and injection rates may need to be varied to ensure well rates are not detrimental to ultimate recovery.

Well Location and Operation

With respect to paragraph 79(b) of the *Framework Regulations*, an operator must identify the number of wells and their locations to provide for maximum recovery from a pool or zone. Factors that should be considered when selecting development well locations include:

- Positioning of wells (e.g., Have structural and stratigraphic position been optimized? If fractures or faults exist, have they been considered in the positioning of development wells to maximize recovery?)

- Proximity of the well to fluid contacts (e.g., Are the wells located too close to a contact, risking premature breakthrough?)
- Porosity and permeability of the reservoir(s) (e.g., The nature and distribution of porosity and permeability in each reservoir and degree of aquifer connectivity should be fully evaluated.)
- Cut-off criteria used to position wells (e.g., Is there a minimum net pay, pore volume or productivity criterion used? If so, is it reasonable?)
- Target production and injection rates
- Spacing of producers (e.g., Does well spacing provide adequate drainage of the various hydrocarbon bearing intervals comprising the pool?)
- Spacing of injectors (e.g., Does the well spacing provide for adequate pressure support and good sweep efficiency?)
- Potential for secondary and tertiary recovery
- Optimal well orientation (e.g., Would horizontal, deviated or vertical wells allow for improved recovery?)
- Potential drainage of more than one pool, if applicable (e.g., Does the well placement provide opportunity for the drainage of multiple pools or zones, i.e., those to be developed, and pools and zones that have been identified but not proposed for development? Is commingled production an option?)
- Capacity of production facilities (e.g., Have adequate well slots been provided to allow for upside or future potential development opportunities?)

The planned number of wells and their locations may be modified based on production experience and new geological and reservoir data. Well number and locations should be examined annually as part of the Annual Production Report referred to in section 202 of the *Framework Regulations,* or as requested by the *Regulator*.

Studies of Infill Drilling and Enhanced Recovery

With respect to paragraph 79(c) of the *Framework Regulations*, the operator will be required to undertake studies if the *Regulator* determines that such studies are justified. Decisions on the need for infill drilling and enhanced recovery studies will be made in consultation with the operator.

Section 80 – Commingled Production

80 (1) It is prohibited for an operator to engage in commingled production unless approved by the Board.

Approval by the Board

(2) The Board must approve commingled production if the operator demonstrates that it will maximize the recovery of petroleum.

Measurement and allocation

(3) If the operator engages in commingled production, it must 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 set out in sections 74 to 78.

Operators should apply for approval of commingled production on an individual well basis. In considering whether to approve an application for commingled production, the *Regulator* will evaluate whether:

- plans for production testing the well will allow adequate assessment of initial inflow parameters and reservoir characteristics for each pool;
- the planned data acquisition program will permit adequate characterization of the fluid properties of each pool to allow for effective reservoir management;
- the planned data acquisition program is sufficient to allow production from each pool in the commingled well to be allocated in accordance with good measurement practices;
- ongoing surveillance of the well will be carried out to ensure the accuracy of production allocation throughout the life of the well; and
- the resource management plan adequately documents the pool management principles set out above.

The operator should submit any other information that supports the approval. A commingled production approval for a well or pool may be revoked if, in the opinion of the *Regulator*, the operator is not able to reasonably estimate and document the allocation of flow. In addition, operators are expected to ensure that sufficient data is obtained on an ongoing basis to understand reservoir drainage and to justify reservoir management and development decisions.

Section 81 – Pilot Scheme

81 (1) An operator may develop and implement a pilot scheme that applies technology in relation to the commercial production of petroleum from a pool, field or zone that is accessible from a production installation and in relation to which there is an approved development plan for the purpose of obtaining information on reservoir, production or technology performance in order to optimize production performance under the development plan or to determine whether the development plan requires an amendment for production performance to be optimized.

Duration and interim evaluations

(2) The Board must establish

(a) the duration of the pilot scheme, based on the time required to achieve the stated objectives; and
(b) the intervals at which interim evaluations of the pilot scheme are to be conducted and reported to the Board.

Completion of pilot scheme

(3) On completion of the pilot scheme, the operator must ensure that any production activities undertaken for the purpose of the scheme are discontinued.

No guidance required at this time.

Sections 82 – 84 – Prohibition against Flaring or Venting and Venting Limits

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Prohibition against flaring or venting

82 It is prohibited for an operator to flare or vent gas unless
(a) the Board authorizes flaring or venting as part of the authorization;
(b) the flaring or venting occurs during a formation flow test approved by the Board under subsection 63(5); or
(c) it is necessary in order to remediate an emergency situation that may cause serious risk to human health or safety and the Board is notified, as soon as the circumstances permit, of the flaring or venting and of the volume flared or vented.

Venting limit

83 (1) An operator must ensure that the volume of gas vented under paragraph 82(a) per installation during a year is not greater than 15 000 standard m^3.

Definition of vented

(2) For the purpose of subsection (1), vented means emitted in a controlled manner, other than as a result of combustion, from an installation due to
(a) the design of equipment or operational procedures at the installation; or
(b) the occurrence of an event that pressurizes the gas beyond the capacity of the equipment at the installation to retain the gas.

Gas emissions

84(1) The operator must ensure that the emissions of gas from the seals of a centrifugal compressor or reciprocating compressor at an installation are

(a) captured and routed to gas conservation equipment or gas destruction equipment; or
(b) routed to vents that release those emissions to the atmosphere.

Flow rate measurement device

(2) The operator must ensure that the flow rate of emissions of gas released from vents referred to in paragraph (1)(b) is measured by means of a continuous monitoring device that is

(a) calibrated in accordance with the manufacturer's recommendations such that its measurements have a maximum margin of error of ±10%;
(b) operated continuously, other than during periods when it is undergoing normal servicing or timely repairs; and
(c) equipped with an alarm that is triggered when the applicable flow rate limit referred to in subsections (3) and (4) for the vents of the compressor is reached.

Flow rate limit - centrifugal compressor

(3) The operator must ensure that the flow rate limit of emissions from the vents of a centrifugal compressor on an installation is
(a) in the case of a compressor that is installed before January 1, 2023,
> ***(i) 0.68 standard m^3/min if the compressor has a rated brake power of greater than or equal to 5 MW, and***
> ***(ii) 0.34 standard m^3/min if the compressor has a rated brake power of less than 5 MW; and***

(b) in the case of a compressor that is installed on or after January 1, 2023, 0.14 standard m^3/min.

Flow rate limit - reciprocating compressor

(4) The operator must ensure that the flow rate limit of emissions that are from the rod packings and distance pieces of a reciprocating compressor on an installation is
(a) if the compressor is installed before January 1, 2023, the product of 0.023 standard m^3/min and the number of pressurized cylinders that the compressor has; or
(b) if the compressor is installed on or after January 1, 2023, the product of 0.001 standard m^3/min and the number of pressurized cylinders that the compressor has.

Corrective measures

(5) If the alarm referred to in paragraph (2)(c) is triggered, the operator must ensure that corrective measures are taken as soon as the circumstances permit to reduce the flow rate to below or equal to the applicable flow rate limit.

General

- With respect to paragraph 82(a) of the *Framework Regulations,* refer to the requirements and associated guidance for clause 8(h)(i)(A) of the *Framework Regulations*.
- With respect to section 83 of the *Framework Regulations,* any planned discharges and the associated discharge limits for should be outlined in the Environmental Protection Plan. Refer to the requirements and associated guidance of section 10 of the *Framework Regulations*.

Gas Flaring and Venting During Formation Flow Testing or Well Cleanup Operations

With respect to the authorization of flaring and venting during formation flow testing or well clean-up operations, the *Regulator* will consider:

- the rationale for the formation flow test or well clean-up;
- the estimated flow rates and volumes proposed to be flared or vented and the period for which gas will be flared or vented, and whether these are necessary to achieve test objectives;
- whether all options to conserve the gas have been considered, and whether any of them are practicable; and
- any potential health or safety hazards and planned measures.

The operator should submit any other information that supports its application for an OA for flaring or venting.

Continuous Flaring and Venting during Production

With respect to the authorization of continuous flaring and venting during production operations, the *Regulator* will consider:

- the period for which it is proposed to flare or vent gas;
- the estimated flow rates and volumes proposed to be flared or vented;
- whether all options to conserve the gas have been considered, and whether any of them are practicable; and
- any potential health or safety hazards and planned measures.

The operator should submit any other information that supports its application for an OA for flaring or venting.

Monitoring

The *Regulator* will monitor the monthly and annual production reports submitted pursuant to sections 198 and 202 of the *Framework Regulations*, respectively, to ensure the operator complies with the conditions attached to any authorization or approval for flaring and venting and associated regulatory requirements. The volumes of gas flared and vented must be within the limits set out in the approval and in accordance with the limits laid out in the regulations. In addition, periodic assessments of the feasibility of conserving the oil and gas will be undertaken.

Section 85 – Prohibition against Oil Burning

85 It is prohibited for an operator to burn oil unless
(a) the Board authorizes burning as part of the authorization;
(b) the burning occurs during a formation flow test approved by the Board under subsection 63(5); or
(c) it is necessary in order to remediate an emergency situation that may cause serious risk to human health or safety and the Board is notified, as soon as the circumstances permit, of the burning and of the amount burned.

With respect to the authorization of oil burning during formation flow testing or well clean-up operations, the *Regulator* will consider:

- the rationale for the formation flow test or well clean-up;
- the estimated flow rates and volumes proposed to be burned and the period for which oil will be burned, and whether these are necessary to achieve test objectives;
- whether all options to conserve the oil have been considered, and whether any of them are practicable; and
- any potential health or safety hazards and the planned precautionary measures.

The operator should submit any other information that supports its application for an OA for oil burning.

SPILL-TREATING AGENT

Sections 86 - 89 – Spill-Treating Agents

Determination of net environmental benefit

86 In determining for the purpose of subsection 161.1(3) (or 165.1(3)) of the Act whether the use of a spill-treating agent is likely to achieve a net environmental benefit, the Chief Conservation Officer must take into account
(a) the assessment of the spill-treating agent's efficacy referred to in paragraph 11(4)(a);
(b) the results of the analysis referred to in paragraph 11(4)(b);
(c) the circumstances referred to in paragraph 11(4)(c);

(d) the methods and protocols referred to in paragraph 11(4)(d);
(e) the monitoring plan referred to in paragraph 11(4)(f); and
(f) the results of any small-scale test conducted in respect of the agent.

Small-scale test

87 (1) An operator must, in respect of any small-scale test of a spill-treating agent referred to in section 161.1 (or 165.1) of the Act, ensure that
(a) before the test is conducted, the Chief Conservation Officer approves the carrying out of the test;
(b) during the test, the quantity of spill-treating agent applied is measured and recorded, the efficacy of the spill-treating agent is monitored and the factors that affect the efficacy are evaluated; and
(c) after the test, the following information is submitted in writing, without delay, to the Chief Conservation Officer:
> ***(i) the volume of oil released and the volume treated,***
> ***(ii) the quantity of spill-treating agent that was used to conduct the test,***
> ***(iii) the circumstances under which the test was conducted, and***
> ***(iv) the efficacy of the use of the spill-treating agent.***

Conditions

(2) The following conditions must be met before a small-scale test is approved:
(a) the operator must demonstrate that the quantity of spill-treating agent to be used in the test is the minimum required to evaluate the efficacy of its use; and
(b) in the case of a request to conduct an offshore subsurface test, the operator must demonstrate that, due to physical or environmental conditions, a surface test cannot be done or its efficacy cannot be readily determined.

Net environmental benefit already determined
(3) No small-scale test is to be approved if the Chief Conservation Officer has made a determination for the purpose of section 161.1 (or 165.1) of the Act regarding the net environmental benefit of the use of the spill-treating agent whose efficacy the test is intended to evaluate.

Oral or written approval

(4) Approval of a small-scale test may be provided orally or in writing, but if approval is provided orally, the Chief Conservation Officer must, as soon as the circumstances permit, provide to the operator written confirmation of the approval.

Variation of approval

88 (1) The Chief Conservation Officer must vary the approval to use a spill-treating agent if new information indicates that a modification to the requirements set out in the approval is necessary to ensure that the approved use is likely to achieve a net environmental benefit.

Revocation of approval

(2) The Chief Conservation Officer must revoke the approval if new information indicates that, despite any modification, use of the agent will not likely achieve a net environmental benefit.

Use of spill-treating agent

89 (1) An operator must ensure that any spill-treating agent is used in accordance with industry standards and best practices for spill-treating agent use, taking into account the local environment.

Equipment and materials

(2) The operator must ensure that all equipment and materials that are listed in the contingency plan as required by paragraph 11(4)(e) are available and maintained in accordance with the manufacturers' specifications and ready for use at all times.

Monitoring plan implementation

(3) The operator must implement the monitoring plan that is included in the contingency plan as required by paragraph 11(4)(f) at the commencement of the use of a spill-treating agent in the case of a spill.

Information to Chief Conservation Officer

(4) The operator must inform the Chief Conservation Officer of the spill-treating agent's efficacy, the effects of its use on the environment and any changes that may require a modification to its use.

Guidance is provided in the *Contingency Plan Guideline*.

WELL ABANDONMENT, SUSPENSION OR COMPLETION

Sections 90 - 93 – Well Abandonment, Suspension or Completion

Conditions for suspension or abandonment

90 (1) An operator that suspends or abandons a well must ensure that the well
(a) can be readily located; and
(b) is left in a condition such that
(i) all petroleum-bearing pools and zones and discrete pressure zones are isolated, and
(ii) any formation fluid is prevented from flowing through or escaping from the well-bore.

Verification of isolation

(2) Before suspending or abandoning the well, the operator must verify the effectiveness of the isolations referred to in subparagraph (1)(b)(i) in accordance with the methods set out in its well approval application under paragraph 17(4)(e).

Additional condition for suspension

91 An operator that suspends a well must ensure that it is inspected and monitored to maintain its integrity and prevent pollution.

Additional condition for abandonment

92 The operator of a well must ensure that, on the abandonment of the well, the seabed is cleared of any material or equipment that might have an adverse effect on the marine environment or interfere with fishing activities or other uses of the sea.

Conditions for drilling installation removal

93 It is prohibited for the operator of a drilling installation to remove the drilling installation from a well or cause it to be removed unless
(a) the well has been abandoned, suspended or completed in accordance with these Regulations; or
(b) the removal of the drilling installation is for emergency purposes.

a. Well Barrier/Integrity Expectations for Suspended and Abandoned Wells

In the case of a well or zone abandonment, or in the case in which a well or zone is being suspended for an extended period:

- The operator should ensure that the fluid in abandoned or suspended wells is suitable to minimize corrosion and prevent freezing.
- Guidance and additional details related to well abandonment or suspension is provided in *NORSOK D-010 Well integrity in drilling and well operations*. This includes expectations related to pulling casing or tubing and verification of well barrier elements. Expectations related to suspension terminology and timeframes are described below.

b. Short-Term Well Suspensions

When well operations are temporarily suspended because of poor physical and environmental conditions (including ice) or any other reason, the well must be left in a state consistent with section 90 of the *Framework Regulations*. This typically applies to wells interrupted during well construction, workover or intervention whereby the well operations are suspended and not the well. Examples of possible barrier elements in a short-term suspension could be any two of the following:

- Drilling fluid (if testing has proven that the fluid properties can be maintained for the short suspended duration and the fluid adequately overbalances possible well pressure)
- Suspension packers
- Mechanical plugs
- Cemented casing/liner strings
- Cement plugs
- Closed BOP stack

The operator is responsible for ensuring the ongoing effectiveness of well barriers to prevent pollution, and in accordance with section 91 of the *Framework Regulations* must conduct inspections and monitoring of the wellhead to confirm surface barrier effectiveness.

When measures are taken to secure a well and move the installation off location, the *Regulator* should be notified via the event notification process referred to in the *Incident Reporting and Investigation Guideline*. If a drilling installation leaves the well location, it must be done in accordance with section 93 of the *Framework Regulations*.

c. Extended Term Well Suspensions

When a drilling or production operation is halted for a longer duration and the well has been suspended with two verified well barrier envelopes suitable for the duration of the suspension, the following should be considered:

- Suspension timeframes should be as short as reasonably possible, and in any case no longer than is necessary to re-task the well for other use or abandonment in a future drilling campaign. An outline should be provided of all the barriers in place, verification method of the barriers and the expected suspension timeframe.

- Any well that is to be suspended for an extended period after it is completed must meet the requirements of sections 90 and 91 of the *Framework Regulations*.
- It is acknowledged that there may be circumstances when an extended suspension period is required. In this case, an operator should manage suspension timeframes to within five years from the time of suspension and this should be in accordance with the temporal scope outlined in the Environmental Assessment and Impact Assessment applicable to that well. Extended term well suspensions where the reservoir is abandoned or the only activity remaining is wellhead removal should be discussed with the *Regulator* on a case-by-case basis. Rationale for an extended term well suspension should include the overall status of the well, the barriers in place, and associated monitoring capabilities.
- The specific time limit to which the suspension applies, along with any plans to monitor and inspect the well during the period, must be described in the well approval and the associated **Notification to Abandon/Suspend** as required by paragraphs 17(4)(d) and (e) of the *Framework Regulations*.
- A plan should be submitted and accepted by the CCO, no later than two years after the suspension period has started, with the operator's intentions for use or abandonment of the well.
- The operator is expected to diligently manage any inventory of suspended wells with the goal of minimizing such inventory. The scope of an operator's inventory will be considered when evaluating requests for extended suspension periods.
- The operator should report the status of suspended development wells annually as part of the Annual Production Report submitted pursuant to section 202 of the *Framework Regulations*.

d. Well Abandonment

A well is considered abandoned when the well has permanent plugs installed and verified as isolating the reservoir and any hazardous substances within the well from the environment, has all necessary well components removed, and has the seabed cleared of debris in accordance with sections 90, 92 and 93 of the *Framework Regulations*. Well abandonment should be captured under either an approved ADW or ACW and the associated Notification to Abandon.

e. Seafloor Clearing

When a well is abandoned, all casing should be cut off at a depth below the SF, at which depth damage to the casing by ice scour cannot reasonably be expected, well barriers are left uncompromised, and interference with the activities of other users of the sea cannot reasonably be expected, or a minimum depth below SF of 1 m, whichever is greater. In addition, all debris should be removed from the SF. Visual surveys should be undertaken to confirm. If the well is within an excavated drill centre, the cut-off depth will be evaluated on a case-by-case by the *Regulator* which will consider requirements of the associated *Development Plan* and associated Environmental Assessment and Impact Assessment approvals.

The casing and wellhead may be left in place above the seabed to a height stipulated in the authorization and the associated ADW if the following conditions are met:

- There is no reasonable expectation of interference with the activities of other users of the sea or of ice scour.
- The potential of leaving casing and wellhead in place at a well site has been assessed as part of the associated Environmental Assessment and Impact Assessment.
- It is not prohibited in any Decision issued by the Minister of ECCC in respect of that production project or drilling program or in NL, for exploratory drilling programs, the *Regulations Respecting Excluded Physical Activities (Newfoundland and Labrador Offshore Exploratory Wells*), as the case may be.
- Any requirements for communication or engagement in any Decision issued by the Minister of ECCC in respect of that production project or drilling program or in NL, for exploratory drilling programs, the *Regulations Respecting Excluded Physical Activities (Newfoundland and Labrador Offshore Exploratory Wells*), as the case may be, have been met.
- Measurements are communicated in the Notice to Abandon and the Well Termination Record.

In cases in which the operator cannot remove the casing and wellhead as planned during abandonment (e.g., several attempts to remove the wellhead have failed) the *Regulator* will consider a request to leave the casing and wellhead in place to a stipulated height above the seabed. This request will require engagement with other authorities (e.g., DFO, CCG) and may require additional review in accordance with the IAA.

PART 9: DIVING PROJECTS

Section 94 – Vessel used in Diving Project

94 An operator that conducts a diving project must, in respect of a vessel used in the diving project, ensure that
(a) the vessel is capable of providing the necessary dive support functions and operating safely;
(b) the vessel is designed to withstand or avoid, without loss of its overall structural integrity or failure of its main safety functions, all foreseeable site-specific physical and environmental conditions or any foreseeable combination of those conditions;
(c) the vessel is a Safety Convention vessel, as defined in section 2 of the Canada Shipping Act, 2001, and holds a valid certificate of class issued by a classification society;
(d) if a permanent diving system is installed on the vessel, the certificate of class referred to in paragraph (c) includes a valid class notation for diving issued by the classification society referred to in that paragraph; and
(e) a competent third party has assessed and certified the sea fastening of any equipment that is temporarily installed on the vessel for the diving project.

- Refer to the requirements and associated guidance in Part 32 of the *OHS Regulations*.
- With respect to paragraph 94(b) of the *Framework Regulations*, refer to the associated guidance for determining physical and environmental conditions under section 104 of the *Framework Guideline* (NOTE: section 104 of the *Framework Regulations* does not apply to a diving vessel).
- Additional guidance is provided in the following documents:
    - *CSA Z275.1 Hyperbaric operations and work in compressed air environments.*
    - The available publications related to diving on the IMCA website.
    - Flag state and classification society rules.

Section 95 – Dynamic Positioning System

95 (1) An operator must ensure that the dynamic positioning system on a vessel that is used in a diving project
(a) includes safety-critical systems and components with sufficient segregation and redundancy to maintain the vessel's position in the event that credible scenarios of equipment failure, fire or flooding are realized;
(b) includes systems to monitor the parameters of critical system operability and the integrity of the dynamic positioning system and to provide alerts for critical system faults;
(c) has sufficient redundancy to protect divers while diving;
(d) is designed based on numerical analysis and model testing to ensure that the vessel's position reference and directional control can be maintained within specified tolerances that satisfy design operational requirements in relation to all functional loads and environmental loads to which the system may be subjected; and
(e) is designed to ensure that, if the diving project involves saturation diving, the dynamic positioning system can withstand the loss from fire or flooding of all of its components situated in any one watertight compartment or fire subdivision of the vessel.

Verification

(2) After the design of the dynamic positioning system is completed, the operator must ensure that a failure modes and effects analysis is conducted to verify that the dynamic positioning system meets the requirements set out in subsection (1).

Maintenance

(3) The operator must ensure that the dynamic positioning system is maintained so that it continues to perform in accordance with its design specifications.

- Refer to the requirements and associated guidance for DP in Part 32 of the *OHS Regulations*.
- With respect to paragraph 95(1)(a) of the *Framework Regulations*, the DP system should meet the requirements of IMO Equipment Class 3 or equivalent.
- With respect to paragraph 95(1)(d) of the *Framework Regulations*, refer to the associated guidance under paragraph 94(b) of the *Framework Regulations*.
- With respect to subsection 95(2) of the *Framework Regulations*, refer to section B.3.2 of *ISO 31010 Risk management - Risk assessment techniques* and *IMCA M166 Code of Practice on Failure Modes and Effects Analysis (FMEA).* In addition to conducting a design verification, sea trials should be conducted to verify the FMEA and to demonstrate the ability of the system to maintain position and heading in the physical and environmental conditions experienced in this operating area. Equipment, operating limits and procedures may have to be adjusted as a result. Additional considerations for an FMEA are as follows:

  - The FMEA team should include at least two members of the dive team, preferably the Dive Safety Supervisor and one Dive Supervisor.
  - All members of a FMEA team, including the members from the dive team, should receive formal training in the FMEA method.
  - The scope of the FMEA should consider the physical and environmental conditions experienced in the *Offshore Area*.

  If the FMEA already exists, it is expected that persons involved in the dive team for the Diving Project, inclusive of Dive Safety Supervisors, review the FMEA and the associated outcomes and make any additional recommendations, if necessary.

- Additional guidance is provided in the following:
  - SOLAS and associated IMO codes, resolutions and circulars.
  - Flag state and classification society rules. (NOTE: DP systems should also have class notation or equivalent from the classification society or CA).
  - IMCA publications related to DP systems.

Section 96 – Light Dive Craft

96 (1) The operator must ensure that any light dive craft that is used for a diving project is
(a) fit for the purposes for which it is to be used; and
(b) designed to withstand or avoid, without loss of its overall structural integrity or failure of its main safety functions, all foreseeable site-specific physical and environmental conditions or any foreseeable combination of those conditions.

Dive support vessel

(2) The operator must ensure, during all dives from a light dive craft, the availability of a dive support vessel that

(a) is fitted with emergency equipment, including a fast rescue boat, that can provide assistance to the light dive craft in any foreseeable emergency situation; and
(b) has a launch and recovery system for the light dive craft that has been verified and certified by the certifying authority as being fit for the purposes for which it is to be used.

Definition of light dive craft

(3) In this section, light dive craft means a small vessel or secondary craft that is equipped to deploy divers from a primary vessel.

- Refer to the requirements and associated guidance in Part 32 of the *OHS Regulations*.
- The light dive craft and mother craft arrangement should be certified as fit for purpose by the CA.
- With respect to paragraph 96(2)(a) of the *Framework Regulations*, the fast rescue boat should be capable of towing the light dive craft and provided with towing equipment.
- Additional guidance is provided in *IMCA D015 Mobile/Portable/Daughtercraft Surface Supplied Systems*. However, it should be noted that the use of self-contained underwater breathing apparatus is not prohibited pursuant to section 166 of the *OHS Regulations*.

PART 10: INSTALLATIONS, WELLS AND PIPELINES

Section 97 – Definitions

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97 The following definitions apply in this Part.

air gap means the clearance between the highest water or ice surface that occurs during extreme environmental conditions and the lowest exposed part of an installation not designed to withstand wave or ice impingement.

control station means a work area that is not continuously staffed that provides an alternative location to a control centre and the minimum necessary control equipment to enable essential management of the installation or of specific key systems.

damaged condition means, with respect to a floating platform, the condition of the platform after it has suffered damage up to the extent determined in accordance with the applicable provisions of the MODU Code or, in the case of a platform that is not a mobile offshore drilling unit, the applicable rules of a classification society.

***design service life** means the anticipated period during which any installation, including its systems or equipment, is to be used for its intended purpose, with anticipated maintenance but without substantial repair.*

***hazardous area** means an area on an installation where flammable, explosive or combustible mixtures are or are likely to be present in sufficient quantities and for sufficient periods of time to require special precautions to be taken in the selection, installation or use of machinery and electrical equipment to prevent a fire or explosion.*

***IS Code** means the annex to International Maritime Organization Resolution MSC.267(85), International Code on Intact Stability, 2008.*

***MODU Code** means the annex to International Maritime Organization Resolution A.1023(26), Code for the Construction and Equipment of Mobile Offshore Drilling Units, 2009.*

***process vessel** means a heater, dehydrator, separator, treater or any other pressurized vessel used in the processing or treatment of produced petroleum.*

***unattended installation** means an installation on which persons are not normally present and in respect of which, when persons are present, it is for the purpose of performing operational duties, maintenance or inspections that will not require an overnight stay.*

No guidance required at this time.

INSTALLATIONS

General

Section 98 – Safety and Environmental Protection

***98** An operator must ensure that an installation, including its systems and equipment, is designed, constructed, installed, arranged and commissioned so that it is fit for the purposes for which it is to be used and can be operated safely without posing a threat to persons or the environment.*

No guidance required at this time.

Section 99 – Design of Installation

99 For the purpose of meeting the requirement under section 98 in respect of design, an operator must ensure that an installation, including its systems and equipment, is designed in accordance with the measures referred to in clauses 9(2)(b)(v)(A) and 10(2)(b)(v)(A) that are described in the operator's safety plan and environmental protection plan, respectively.

No guidance required at this time.

Section 100 - Quality Assurance Program

100 (1) An operator must, for the purpose of ensuring that an installation, including its systems and equipment, is fit for the purposes for which it is to be used, develop a quality assurance program that meets the following requirements:
(a) it must be set out in writing;
(b) it must be comprehensive;
(c) it must include a process to achieve quality objectives and to comply with the requirements of these Regulations;
(d) it must include the policies on which it is based and a process to communicate the policies to personnel and all other affected persons;
(e) it must set out the roles, responsibilities and authorities of all persons exercising functions under it, as well as the processes for making those persons aware of their roles, responsibilities and authorities and ensuring that they comply with them;
(f) it must include processes for establishing and maintaining measurable goals and performance indicators that are applicable to it;
(g) it must include processes for its periodic internal audit and review to identify areas for improvement and the corrective measures to be implemented if deficiencies are identified;
(h) it must include processes for ensuring that its integrity is preserved when changes to it are planned or implemented;
(i) it must include processes for internal and external reporting on its performance; and
(j) it must identify the resources that are necessary to ensure that the requirements under this section are being met.

Implementation

(2) The operator must ensure that each phase of the life cycle of the installation, from its design up to and including its decommissioning and abandonment, is carried out in accordance with the program and that any activity relating to the installation that is carried out under the control of a third party is also carried out in accordance with a quality assurance program.

Accessibility

(3) The operator must ensure that the processes and policies that are included in the program referred to in subsection (1) are readily accessible for consultation and examination.

Organization

(4) The operator must ensure that the documentation relating to the program referred to in subsection (1) is organized and set out in a logical fashion to allow for ease of understanding and efficient implementation.

Processes and procedures

(5) In this section, a reference to a process includes any procedures that are necessary to implement the process.

- The design, construction, installation and commissioning of all new or existing installations should be completed or undertaken in accordance with a quality management system that follows the principles of *ISO 9001 Quality Management Systems – Requirements.* Additional guidance for quality management is provided in *ISO 19900 Petroleum and natural gas industries — General requirements for offshore structures*.
- Any equipment or materials brought onboard and any providers of service and suppliers should also follow a quality management system that follows the principles of *ISO 9001 Quality Management Systems – Requirements.* Particular requirements of the operator should also be considered.
- The inspection, maintenance, operation, modification, suspension, decommissioning or abandonment of an installation should also be completed or undertaken in accordance with a quality management system that follows the principles of *ISO 9001 Quality Management Systems – Requirements* and in accordance with the requirements and associated guidance for management systems under Part 3 of the *Framework Regulations*.

Sections 101 - 102 - Work Permits

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101 (1) An operator must ensure that a work permit that is required under this Part is issued in either paper or electronic form, is approved by a person other than the one who issued it and sets out the following information:
(a) the name of the person who issued it and the person who approved it;
(b) the name of each person to whom it is issued;
(c) the periods during which it is valid;
(d) the work or activity to which it relates, the location at which the work or activity is to be carried out and any conditions to which the carrying out of the work or activity is subject; and

(e) any circumstances under which the work or activity is to be carried out that may have an effect on the safety and environmental risks associated with it, including

> ***(i) physical and environmental conditions,***
> ***(ii) any impediments to the proper use of any system or equipment, and***
> ***(iii) any other activities being carried out in the area, with reference to the permit or certificate associated with those activities, if applicable.***

Signatures

(2) The work permit must bear the signatures of the person who issued it, the person who approved it and every person involved in the work or activity to which it relates, certifying that they have read and understood its contents.

Operator obligations

102 (1) An operator must ensure that
(a) any work or activity that requires a work permit is done in accordance with the permit; and
(b) any work permit that is issued is made readily accessible for the duration of the work or activity to which it relates.

Retention of copy

(2) The operator must retain a copy of each work permit for at least three years after the day on which the work or activity to which it relates is completed.

General

Refer to the requirements and associated guidance for work permits under Part 10 of the *OHS Regulations*. While the *OHS Regulations* focus on OHS, the same guidance should be considered for the purposes of preventing pollution and ensuring the ongoing integrity of the installation.

Activities Conducted under a Work Permit

Refer to the requirements and associated guidance for activities conducted under a work permit under Part 10 of the *OHS Regulations*. In addition to the requirements and associated guidance in the *OHS Regulations*, refer to the following in the *Framework Regulations*:

- Hot work (refer to subsections 115(8) and (9) of the *Framework Regulations).*
- Testing and maintenance of the fire and gas detection system (refer to subsections 132(6), (7) and (8) of the *Framework Regulations).*
- Testing and maintenance of the emergency shutdown system (refer to subsections 133(6), (7) and (8) of the *Framework Regulations).*

In addition, in consideration of paragraph 4(1)(z) of the *Framework Regulations*, it is recommended that the work permit process include the following:

- The operation of manual valves in which an inadvertent or uncontrolled operation could result in harm to the environment. Refer to guidance under section 73 of the *Framework Guideline*.
- The management of temporary openings in fire rated divisions (e.g., removal of hatches, running new cables through transits, leaving fire doors open). Refer to guidance under section 112 of the *Framework Guideline*.
- The inhibit or override of control and monitoring systems as referred to in sections 123, 124, 125 and 169 of the *Framework Regulations*.
- The isolation or de-isolation of safety and environmentally critical devices.
- Activities that can pose harm to the environment if not controlled, coordinated or communicated (e.g., VSP, use of explosives around mammals).
- Simultaneous activities that should or should not occur concurrently as the planned activity. Refer to guidance provided in the *Contingency Plan Guideline* for simultaneous activities.
- Because of the potential for petroleum products to mix with water, any bilge well or tank should be treated as a confined space and assumed to have H_2S. Any entry for cleaning, maintenance, etc., should be done under a work permit.

Section 103 – Innovations

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103 (1) An operator must ensure that any technology, including any technology that is used in relation to materials, design methods, joining techniques or construction techniques, that has not been previously used in comparable situations is not used in relation to an installation unless
(a) engineering studies, prototypes or model tests demonstrate that the technology is safe and fit for the purposes for which it is to be used; and
(b) the technology is verified by a competent third party, in accordance with industry standards and best practices for technology qualification.

Technology qualification program

(2) The operator must develop a technology qualification program that sets out the performance monitoring and inspection measures that are necessary to determine the effectiveness of any technology referred to in subsection (1) that it intends to use.

Program implementation and update

(3) The operator must ensure that the program is implemented and periodically updated.

- This includes newly-developed technologies or technologies that have not been commercially applied in equivalent physical and environmental conditions or applications for which they are intended or proposed, that can have an impact on safety, the integrity of the installation or wells, or the protection of the environment. This should also include any new products, analysis tools or known products used in a new way, and should be interpreted to include software (e.g., remote operation, artificial intelligence) and associated hardware.
- The "competent third party" should not have been involved with the original design. If their organization was involved in the original design, the verification should be undertaken by a competent person in a branch or business unit separate from those that are developing the technology. In certain circumstances, the CA may provide this verification as long as they are not involved with providing input into the original design. The engagement of the CA must consider the conflict of interest requirements of section 29 of the *Framework Regulations* and associated guidance.
- "Comparable situations" should be interpreted to include the oil and gas industry or similar operating environments (e.g., mining, nuclear, marine).
- The protocols for assessing any new technology should follow the processes described in one of the following:
  - *DNV-RP-A203 Technology Qualification*; or
  - *LR Guidance Notes for Technology Qualification*, provided the entire technology qualification process is independently verified.
- The implementation of any new technology or method should follow the above processesand associated management of change processes. This should include engagement with all affected parties, and must include the *Regulator* and the CA for safety-critical elements, as described in section 162 of the *Framework Regulations* and the associated guidance.

Section 104 – Physical and Environmental Conditions

104 (1) An operator must ensure that an installation is designed to withstand or avoid all foreseeable site-specific physical and environmental conditions, or any foreseeable combination of those conditions, without compromising its structural integrity or that of any of its systems or equipment that are critical to safety or to the protection of the environment.

Criteria

(2) The operator must ensure that the design of an installation is based on criteria that are determined using evidence-based regional and site-specific data, statistical analysis and modelling of physical and environmental conditions, including:
(a) oceanographic conditions, including any completely or partially submerged potential navigational hazards;
(b) meteorological conditions, including the number of daylight hours;
(c) geotechnical conditions and geohazards;
(d) ice conditions and any other conditions associated with cold regions; and

(e) any other physical and environmental conditions or naturally occurring phenomena that may adversely affect the installation.

Ice conditions

(3) The operator must ensure that an installation that is to be operated where ice conditions may exist is designed and operated to
(a) minimize or avoid environmental loads associated with ice or ice and snow accumulation on the installation, including on its structural components;
(b) ensure that the ice conditions will not adversely affect the functionality of any systems or equipment that are critical to safety or to the protection of the environment;
(c) protect risers, offloading systems and other subsea systems from the ice conditions; and
(d) in the case of a mobile offshore platform or vessel,
(i) prevent damage to propulsion or positioning systems from the ice conditions, and
(ii) ensure safe transit through ice-infested waters.

Redundancy

(4) The operator must ensure that there is redundancy included in any measures implemented for the purposes of paragraph (3)(a) in relation to ice and snow accumulation and removal.

Cold climate – safety plan and environmental protection plan

(5) The operator must ensure that an installation that is to be operated in a cold climate is designed, winterized and operated in accordance with the measures referred to in clauses 9(2)(b)(v)(B) and 10(2)(b)(v)(B) that are described in the operator's safety plan and environmental protection plan, respectively.

Cold climate - design

(6) An installation that is to be operated in a cold climate must be designed to
(a) ensure the functionality in that climate of the installation and all of its systems and equipment that are critical to safety or to the protection of the environment, including in the case of property changes in fluids; and
(b) prevent any impact or damage to electrical cabling in open or unheated spaces and ensure that the cabling maintains its properties under cold-climate conditions.

General

- With respect to subsections 104(1) and (2) of the *Framework Regulations*, operators should refer to the following codes and the references within these codes to offshore NL, NS or Canada related requirements:

- *ISO 19900 Petroleum and natural gas industries — General requirements for offshore structures*
- *ISO 19901-1 Petroleum and natural gas industries – Specific Requirements for Offshore Structures – Part 1: Metocean Design and Operating Considerations*
- *ISO 19901-2 Petroleum and natural gas industries — Specific requirements for offshore structures — Part 2: Seismic design procedures and criteria*
- *ISO 19901-4 Petroleum and natural gas industries — Specific requirements for offshore structures — Part 4: Geotechnical and foundation design considerations*
- *ISO 19901-8 Oil and gas industries including lower carbon energy — Offshore structures — Part 8: Marine soil investigations*
- *ISO 19901-10 Petroleum and natural gas industries — Specific requirements for offshore structures — Part 10: Marine geophysical investigations*
- *ISO 19905-1 Oil and gas industries including lower carbon energy — Site-specific assessment of mobile offshore units — Part 1: Jack-ups: elevated at a site*
- *ISO 19905-3 Petroleum and natural gas industries — Site-specific assessment of mobile offshore units*
- Flag state and classification society rules

- In addition to the above references, refer to the requirements and associated guidance under section 105 of the *Framework Regulations*.

Criteria

- With respect to subsection 104(2) of the *Framework Regulations*, operators should refer to *ISO 19901-1 Petroleum and natural gas industries — Specific requirements for offshore structures — Part 1: Metocean design and operating considerations*. In applying this code, it should be noted that the referenced table and data has not been updated since 2013 for current areas of operation and data for Offshore Labrador is not included.
- Up-to-date data may be available from the following sources:
  - ECCC Climate Research Division:
    - *GROW Fine North Atlantic Basin (GROWFAB) Hindcast* (collaborated with Oceanweather Inc.)
    - *Meteorological Service of Canada's MSC50 North Atlantic Wave Hindcast* (based on data from 1954 to 2018)
    - *Tools to obtain historical climate data*, but the availability of marine data may be limited.
    - *Canadian Centre for Climate Services*
    - *Canadian Ice Service*
  - *DFO Marine Environmental Data* (provides real-time, near real-time and historical ocean monitoring data)
  - *National Oceanic and Atmospheric Administration (NOAA)*
  - *Centre for Cold Ocean Research (C-CORE)*
- With respect to paragraph 104(2)(a) of the *Framework Regulations*, "oceanographic conditions" is interpreted to include:

    - waves and sea states – parameters to measure include:
        - wave direction;
        - swell height, period and direction;
        - mean wave height / significant wave height, period and direction;
        - maximum combined wave height / maximum combined sea;
        - average wave period; and
        - wave spectrum peak period;
    - currents – measurements should:
        - include direction and speed at locations near surface, mid-depth, and near bottom;
        - be taken with a view to resolving the vertical structure and temporal variability of currents during the program period; and
        - be continual from current meters moored in fixed positions near the installation;
    - sea surface temperature and sea temperature at the current measurement depth(s);
    - sea salinity at the current measurement depth(s);
    - pressure at the current measurement depth(s);
    - tides;
    - marine growth;
    - water depth / bathymetry; and
    - variations in sea level.
- With respect to paragraph 104(2)(b) of the *Framework Regulations*, “meteorological conditions” is interpreted to include:
    - wind speed, prevailing direction and gust speed at sea surface and relevant elevations with respect to the installation;
    - air / barometric pressure;
    - relative humidity;
    - air temperature at sea surface and relevant elevations with respect to the installation;
    - type and rate of precipitation;
    - visibility (horizontal and vertical); and
    - daylight hours – this parameter should take into account the location of the installation, the impact on transportation to and from the facility, the design of lighting systems, and the potential impact of lighting on wildlife (e.g., birds).
- With respect to paragraph 104(2)(c) of the *Framework Regulations*, “geotechnical conditions and geohazards” is interpreted to include seismic hazards, slope stability, sea floor and sediment characteristics, scour, erosion, subsidence, gas hydrates, shallow gas and permafrost conditions.
- With respect to paragraph 104(2)(d) of the *Framework Regulations*, “ice conditions” is interpreted to include:
    - the extent of pack ice, its prevalence at the operations location, the thickness and/or strength of pack ice, and its speed;
    - the extent of iceberg occurrence, iceberg prevalence and size distribution at the operations location, drift speed and direction;
    - the potential for iceberg scour, including depth relative to subsea infrastructure;
    - the potential for strudel scouring; and
    - the potential for ice accretion on surfaces.

Ice Conditions and Cold Climate Operation

With respect to subsections 104(3), (4), (5) and (6) of the *Framework Regulations*, and in addition to the documents referenced above, refer also to the following:

- *ISO 19906 Petroleum and natural gas industries — Arctic offshore structures*
- *ISO 35101 Petroleum and natural gas industries — Arctic operations — Working environment*
- *ISO 35106 Petroleum and natural gas industries: Arctic Operations: Metocean, Ice and Seabed Data*
- Flag state and classification society rules

In addition, if design, operation, inspection or maintenance requirements for cold physical and environmental condition operations are specified in a code or standard that has been adopted, these requirements should be considered.

Section 105 – Design for Intended Use and Location

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105 (1) An operator must ensure that the structural components of an installation and any of its ancillary structures, including skids and modules, are designed for their intended use and location, taking into account
(a) the nature of the works and activities to be undertaken on and around the installation and the hazards associated with those works and activities;
(b) material properties and dimensions of the installation that may vary over time;
(c) failure modes; and
(d) applicable safety factors.

Analyses, tests, modelling and investigations

(2) The design of the structural components of an installation and any of its ancillary structures, including skids and modules, must be based on any analyses, model tests, numerical modelling and site investigations that are necessary to determine the behaviour of the installation and of the soils that support it or its mooring systems under all foreseeable operating, construction, transportation and installation conditions – including those involving geohazards - and under all foreseeable loads during the design service life of the installation.

Design criteria

(3) The structural components of an installation and any of its ancillary structures, including skids and modules, must be designed to
(a) withstand extreme loads that may occur during their construction and anticipated use;
(b) perform as intended during their operation under all anticipated normal loads;
(c) not fail under repeated loads;
(d) prevent damage that is disproportionate to the cause;

(e) prevent localized damage from leading to progressive or complete loss of integrity of the structure;
(f) maintain structural integrity for the time necessary to safely evacuate all persons from the installation in the event of major damage caused by foreseeable hazards;
(g) in the case of a floating platform,

> ***(i) have sufficient stability and buoyancy reserve in the case of damage to ensure that credible scenarios of unintended flooding, if realized, do not result in the loss of the structure, and***
> ***(ii) incorporate sufficient redundancy in station-keeping systems to ensure that the structure can withstand the loss of a station-keeping component; and***

(h) in the case of a self-elevating mobile offshore platform, withstand all loads to which the platform may be subjected in each mode of operation, including in the elevated position and during its removal.

Accidental loads

(4) For the purposes of paragraphs (3)(d) to (f) and (h), the design must take into account all credible accidental load scenarios, including collisions between the installation and a vessel or aircraft.

General

- Refer to the requirements and associated guidance for physical and environmental conditions, risk assessments, materials, passive fire and blast protection, design for removal, transportation and positioning, asset integrity and corrosion in sections 98, 104, 106, 107, 108, 110, 111, 112, 120, 121, 140, 153 and 155 of the *Framework Regulations*.
- Refer to the requirements and associated guidance for other structural considerations in Part 17 of the *OHS Regulations*.
- Guidance on the design, construction, transportation, installation and operations of installations and associated structures based on the type of installation including substructures, topsides, foundations, equipment supports, mooring and the seabed is provided in the ISO 19900 series of standards noted below.

Standards

All Types of Installations:

- *ISO 19900 Petroleum and natural gas industries — General requirements for offshore structures*
- *ISO 19901-1 Petroleum and natural gas industries – Specific Requirements for Offshore Structures – Part 1: Metocean Design and Operating Considerations*
- *ISO 19901-2 Petroleum and natural gas industries – Specific Requirements for Offshore Structures – Part 2: Seismic Design Procedures and Criteria*

- *ISO 19901-3 Oil and gas industries including lower carbon energy – Specific requirements for offshore structures – Part 3: Topsides Structure*
- *ISO 19901-4 Petroleum and natural gas industries – Specific Requirements for Offshore Structures – Part 4: Geotechnical/foundation design criteria*
- *ISO 19901-5 Petroleum and natural gas industries – Specific Requirements for Offshore Structures – Part 5: Weight management*
- *ISO 19901-6 Petroleum and natural gas industries – Specific Requirements for Offshore Structures – Part 6: Marine Operations*
- *ISO 19901-7 Petroleum and natural gas industries – Specific Requirements for Offshore Structures – Part 7: Station keeping systems for floating offshore structures and mobile offshore units*
- *ISO 19901-8 Oil and gas industries including lower carbon energy — Offshore structures — Part 8: Marine soil investigations*
- *ISO 19901-10 Petroleum and natural gas industries — Specific requirements for offshore structures — Part 10: Marine geophysical investigations*
- *ISO 19906 Petroleum and natural gas industries - Arctic Structures*
- Flag state and classification society rules, such as:
  - *DNV-OS-C101 Structural design of offshore units*
  - *DNV-OS-C102 Structural design of offshore ship-shaped and cylindrical units*
  - *DNV-OS-C103 Structural design of column stabilised units*
  - *DNV-OS-C104 Structural design of self-elevating units*
- In addition, the following should be noted with respect to welding in the suite of ISO standards:
  - For structural welding, all weld procedure specifications, qualification reports and welder qualification tests should be verified/certified by a recognized and independent third party organization acceptable to the CA.
  - Before issuance of an OA, NDE can be performed by persons with internationally recognized third party certification (e.g., CAN/CGSB, ISO, ANSI); however, following the issuance of an OA, the requirements of the *OHS Regulations* apply. For the qualifications of persons involved in NDE activity onboard an installation, refer to paragraph 157(1)(p) of the *OHS Regulations* and the associated guidance.
- API also has a suite of standards for structural design. These API standards reference requirements of the ISO standards, and the ISO standards are normative references; however, certain standards may not have not been updated to reflect the latest updates to ISO standards. In addition, these standards contain requirements and recommendations that may not be comparable to the physical and environmental conditions experienced in the *Offshore Area*, so additional considerations will have to be applied.

Fixed Installations (e.g., Fixed Platforms and Jack-ups):

- *ISO 19902 Petroleum and natural gas industries — Fixed steel offshore structures*
- *ISO 19903 Petroleum and natural gas industries — Concrete offshore structures*
- *ISO 19905-1 Oil and gas industries including lower carbon energy — Site-specific assessment of mobile offshore units — Part 1: Jack-ups: elevated at a site*

- *ISO/TR 19905-2 Petroleum and natural gas industries — Site specific assessment of mobile offshore units – Part 2: Jack-ups commentary and detailed sample calculation*

Floating Installations (e.g., Ships, Semi-submersibles, Spars and TLPs):

- *ISO 19903 Petroleum and natural gas industries — Concrete offshore structures*
- *ISO 19904-1 Petroleum and natural gas industries — Floating offshore structures – Part 1: Ship-shaped, semi-submersible, spar and shallow-draught cylindrical structures*
- *ISO 19905-3 Petroleum and natural gas industries — Site-specific assessment of mobile offshore units*

Inspection, Testing and Maintenance

- Refer to requirements and associated guidance for inspection, testing and maintenance of these systems under sections 153, 154, 155, 156, 157 and 158 of the *Framework Regulations*.

Temporary Repairs

Refer to the guidance provided under section 159 of the *Framework Regulations* for temporary repairs.

Section 106 – Conditions for Safe Operation and Survival

106 Based on the results of any analyses, tests, modelling or investigations undertaken under subsection 105(2), the operator must ensure that
(a) all physical and environmental conditions that could pose a hazard to the installation are documented and communicated to all affected personnel;
(b) the environmental limits for the safe operation of the installation are defined, included in operating procedures and communicated to all affected personnel; and
(c) measures to detect, avoid, prevent, manage and reduce the effects of the hazards posed by the physical and environmental conditions are developed and implemented in operations and incorporated into the design of the installation where required.

With respect to section 106 of the *Framework Regulations*:

- Refer to the requirements and associated guidance for Contingency Plans, operating procedures, asset integrity, operations manual and maintenance programs under sections 11, 73, 153, 157 and 158 of the *Framework Regulations*.
- Refer to the requirements and associated guidance for equipment for observing, detecting, measuring, forecasting and recording physical and environmental conditions under section 109 of the *Framework Regulations*.

- Refer also to any limitations that have been established by the CA as part of the issuance of a COF.
- The following should also be considered:
    - For self-elevating platforms, a pilot hole should be drilled.
    - Actual physical and environmental condition data collected during operation should be compared to design parameters to ensure the installation is being operated within its established limits. If an installation has been subjected to conditions outside of its established limits, further analysis should be conducted to determine if the installation remains fit for purpose and to determine if additional measures should be implemented to preclude it from being subject to conditions outside of its established limits.
    - The behavior and condition of the installation and associated equipment should also be monitored on an ongoing basis to assess any degradation or increase in stresses because of physical and environmental conditions or other factors (e.g., changes to the SF, changes to frequency and intensity of temperature, wind and waves, effect of marine growth, effect of motion (e.g., excessive accelerations, ton-cycles). As a result of changes, additional measures may need to be implemented to reduce the risk.
    - Instrumentation for monitoring the behavior and condition of the structure, its foundations or associated equipment should be monitored, inspected, tested and maintained, as necessary.

Section 107 – Risk Assessment - Fire, Explosion and Hazardous Gas

107 (1) An operator must ensure that an assessment of fire and explosion risks and of risks associated with hazardous gas and its containment is conducted in respect of an installation and that the assessment identifies
(a) the types of fires, explosions and hazardous gas releases that could occur, their potential sources and unmitigated consequences, the likelihood of their occurrence and, if applicable, their potential fire or blast loads;
(b) measures to be incorporated into the design of the installation, if practicable, to eliminate the hazards identified under paragraph (a); and
(c) if it is not practicable to eliminate those hazards through design measures, all necessary control measures to reduce the risks associated with the hazards to a level that is as low as reasonably practicable.

Elements for consideration

(2) For the purposes of paragraphs (1)(b) and (c), the assessment must take into account the following elements:
(a) the general layout of the installation;
(b) the production and process activities to be carried out, including well operations;
(c) operating limits of the installation;

(d) the types of fires, explosions and hazardous gas releases identified under paragraph (1)(a) and their duration;
(e) the need for a means of detecting, from the potential sources identified under paragraph (1)(a),
> ***(i) hazardous gas releases, and***
> ***(ii) outbreaks of fire;***

(f) the need for a means of isolating and safely storing hazardous substances, including fuel, explosives and chemicals;
(g) the need for a safe means of escape, evacuation and rescue in the event of a fire, explosion or hazardous gas release; and
(h) the need for a means to ensure levels of emergency shutdown of the installation, systems and equipment in the event of the detection of a hazardous gas release or an outbreak of fire.

General

- Refer to the requirements and associated guidance under section 108 of the *Framework Regulations*.
- The risk assessments should include the following:
  - Initiating events from both internal and external factors.
  - The type of ventilation and whether the release will be confined or unconfined, considering the congestion of equipment in the area.
  - The effect of wind and current on dispersion (inclusive of considering the upper and lower bounds of conditions, such as light to no wind conditions).
  - The potential for migration between areas through penetrations, drains, ducts, piping, etc.
  - The potential for release from any system or equipment installed in a particular area.
  - The effects from fires or release of hazardous gases on a person should include inhalation of toxic fumes from the release, inhalation of byproducts from fires or ignited materials, thermal radiation, inhalation of hot gases, asphyxiation, poor visibility, etc.
  - The effects on critical equipment including thermal radiation.
  - The effects from explosions on a person should also include the effects of overpressure and projectiles.
- Risk assessments should be recompleted if changes are made that affect the inputs, assumptions and associated measures. This would include changes in distribution of persons, process or equipment, including the addition of temporary equipment.

Fire and Explosion

- With respect to fire and explosion risk assessment(s) refer to the following:
  - In addition to the documents referenced in section 108 of the *Framework Guideline*, refer to the following:

    - ISO 19900 series of standards, and in particular *ISO 19901-3 Oil and gas industries including lower carbon energy – Specific requirements for offshore structures – Part 3: Topsides Structure.*
    - *ISO 13702 Petroleum and natural gas industries - Control and mitigation of fires and explosions on offshore production installations - Requirements and guidelines.* It should be noted that specific hazards associated with subsea installations and MODUs are not included, so additional assessment will be needed.
    - *API RP 14J Recommended Practice for Design and Hazards Analysis for Offshore Production Facilities* and *API RP 2FB Recommended Practice for the Design of Offshore Facilities Against Fire and Blast Loading.* It should be noted that the calculation of fire loads in accordance with these practices may result in an underestimation of fire loads, so associated fire loads should be calculated based on guidance referenced in ISO standards.
    - *NORSOK Z-013 Risk and emergency preparedness assessment and NORSOK S-001 Technical Safety*.
    - *NOPSEMA Guidance Note GN 1051 Supporting Safety Studies.*
    - *Health and Safety Executive Offshore Information Sheet 9/2008 Modelling Pool Fires in Offshore Hazard Assessments.*
    - *NFPA 1 – Fire Code* and *NFPA 101 Life Safety Code.* It should be noted that the calculation of fire loads in accordance with these practices may result in an underestimation of fire loads, so associated fire loads should be calculated based on guidance referenced in ISO standards.
    - Flag state and classification society rules.
- The types of fire scenarios to be considered should include the following:
    - Hydrocarbon fires on deck (single or multi-phase jet fires, diffusive gas cloud fires, well blowout fires from drilling or production (e.g., gas-lift, pool fires, running liquid fires, flash fires, fireballs, liquefied natural gas fires and combination thereof)).
    - Hydrocarbon, flammable or combustible fires on the sea surface.
    - Flammable or combustible liquid fires (e.g., chemicals, paint, oxidizers, cooking oils, diesel, methanol, hydraulic fluids, lubricants).
    - Flammable material fires (e.g., pyrophoric iron sulfide, oil soaked insulation or rags).
    - Combustible material fires (e.g., bedding, clothing, rags, wood, rope, paper, laundry lint, cardboard, plastic bottles).
    - Electrical fires.
- The types of explosion scenarios to be considered should include the following:
    - Physical explosions such as explosions within equipment like flare headers or engines, vessel ruptures because of overpressurization or BLEVE (boiling liquid expanding vapor cloud explosion) caused by heat.
    - Explosions from flammable gas or mist.
    - Explosions from combustible spray/mist or dust (e.g., spraying, blasting, powders).
    - Storage, handling and use of explosives.
- With respect to design measures and prevention, detection and mitigation measures for fires and explosions:

- Refer to the requirements and associated guidance for measures under sections 45, 111, 112, 113, 114, 115, 117, 118, 122, 123, 124, 125, 130, 131, 132, 133, 134, 135, 136 and 169 of the *Framework Regulations*.
- Guidance on other measures respecting the installation, operations, maintenance, inspection and testing of selected equipment to reduce the risk of fires and explosions can be found in *NFPA 1 – Fire Code* (e.g., practices for storage of combustibles, cooking equipment, batteries, laboratories, laundry, which are not covered in the ISO and API standards referenced above).
- Guidance for explosion prevention is provided *in NFPA 69 Standard on Explosion Prevention Systems.*
- Guidance for firefighting equipment and related preventive measures in engine rooms, cargo pump rooms, boilers, fired units and hydraulic systems is also provided in *IMO Circular MSC.1/Circ.1321 Guidelines for Measures to Prevent Fire in Engine Rooms and Cargo Pump Rooms*.

Hazardous Gas

- With respect to hazardous gas risk assessment(s) the following should be considered:
  - Refer to the requirements of the *Accord Acts* in relation to "hazardous substances" and the requirements and associated guidance for hazardous substances under Part 31 of the *OHS Regulations* and section 45 of the *Framework Regulations*.
  - Refer to guidance for smoke and gas dispersion and ingress analysis in Annex C.6 of *ISO 17776 Petroleum and natural gas industries — Offshore production installations — Major accident hazard management during the design of new installations*.
- With respect to design measures, and prevention, detection and mitigation measures for hazardous gases, refer to the requirements and associated guidance under sections 45, 113, 114 and 132 of the *Framework Regulations*.

Section 108 - Reliability and Availability

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108 (1) An operator must demonstrate, through a risk and reliability analysis conducted using internationally recognized techniques, the reliability and availability of any system in an installation whose failure could cause or contribute to a major accidental event or whose purpose is to prevent or mitigate the effects of a major accidental event.

Redundancies and measures

(2) The risk and reliability analysis must determine the redundancies and measures that are required to protect a system referred to in subsection (1) from failure, including any redundancies and measures required under this Part for that system.

Results of analysis

(3) The operator must ensure that the results of the risk and reliability analysis are reflected in the design of the installation, its systems and equipment and in any associated operating and maintenance manuals, including the operations manual referred to in section 157.

a. General

- With respect to this section, particular reference should be made to the definitions of “major accidental event” and “safety-critical element” in section 1 of the *Framework Regulations*. It should be noted that “safety-critical element” refers both to equipment that is critical to safety and critical for preventing pollution.
- Refer to the requirements and associated guidance under Part 3 of the *Framework Regulations* and Part 2 of the *OHS Regulations*..
- Refer to any conditions or commitments respecting goals, assumptions or measures provided as part of a *Development Plan* (which includes the concept safety analysis) or associated Environmental Assessment and Impact Assessments.
- With respect to a production project, it is recognized that most operators have incorporated the target levels of safety, assumptions and measures from their concept safety analysis into their ongoing qualititative and quantitative risk assessments. If this is the case, subsections 24(4) and (5) of the *Framework Regulations* apply to the risk and reliability analysis discussed in this section of the regulation.
- Refer to the requirements and associated guidance for the fire, explosion and hazardous substance risk assessments and the escape evacuation and rescue analysis under section 107 and 116 of the *Framework Regulations*, respectively. In addition, several sections of both the *OHS Regulations* and *Framework Regulations* make reference to risk assessments, associated principles and methods that should be considered. Other points of consideration are as follows:
  - When assessing risks, particular attention should be given to industry best practices, the source of information used and the experience, knowledge and mindfulness of persons involved in doing the risk assessment. Measures should also be in place to ensure that persons conducting risk assessments are not subject to unconscious bias.
  - Operators should understand that the limited size of any dataset applicable to this region may mean that statistical inferences are not necessarily meaningful, but the data provides insight into potential incidents and consequences. Historical incident information can also be obtained from the *Regulator* and from the following sources:
    - International Regulators’ Forum website (www.irfoffshoresafety.com)
    - Other petroleum, marine or aviation regulators
    - Industry associations
  - An example list of data sources is also provided in Annex D of *NORSOK Z-013 Risk and emergency preparedness assessment*; however, some of the sources are outdated so current sources of information and data should be included.
  - If there is insufficient, inconclusive or uncertain information, conservative assumptions should be made and other methods applied to assess ALARP (e.g., applying ALARA, precautionary principle).

- To broaden knowledge of the hazards and to foster a culture of safety and environmental protection, risk assessments and associated studies should include engagement with persons who may operate or maintain the installation.

b. Major Accidental Events

With respect to the definition of “major accidental events”, the types of hazards that should be considered when determining major accidental events include the following:

- Physical and environmental conditions (e.g., earthquakes, foundation stability, adverse weather, pack ice)
- Structural failure
- Release of hazardous substances (toxic, flammable, combustible)
- Spills
- Pollution
- Shallow gas releases
- Loss of well control
- Fires (including process and non-process related fires in machinery spaces, storage spaces, laundry rooms and galleys)
- Explosions
- Collisions with a vessel, iceberg or drifting object
- Helicopter crash
- Helicopter ditching
- Failure of pressure systems
- Failure of rotating equipment
- Failure of electrical equipment
- Failure of materials handling equipment
- Dropped or swinging loads
- Loss of support craft, including passenger craft
- Loss of station keeping systems
- Loss of ballast control or stability
- Loss of watertight integrity
- Loss of tow
- Diving
- Accidents during escape, evacuation and rescue
- Epidemic/pandemic
- Security (e.g., bomb threats, terrorism, cyber-attacks)

The list of major accidental events must include any other foreseeable events that may result in multiple fatalities or uncontrolled pollution. The list should also consider the impact from any event that may occur onboard an adjacent installation, vessel or support craft operating in close proximity to the facility as these facilities may also need to have measures in place.

c. Hierarchy of Risk Reduction Measures and Inherent Safety

The hierarchy of risk reduction measures should be selected based on the following:

- Elimination and minimization measures – to eliminate and minimize credible major accidental events through design optimization (also referred to as Inherent Safety or Inherently Safer Design). This includes removal or reduction of hazards, substitution with less hazardous processes or materials, prevention of potential events, using hazardous processes or materials in a way that lowers their potential, fail safe design, simplification of process, layout of equipment, protection of persons from the consequences of potential events, etc.
- Prevention measures – to reduce the likelihood of a major accidental event. This includes management systems, design features of an installation, such as drainage systems, passive fire protection, explosion protection, etc.
- Reduction measures – to detect potential major accidental events. This includes initiation of an action to prevent or reduce escalation (e.g., PSVs, control and monitoring systems, emergency shutdown systems).
- Mitigation measures – to provide protection from major accidental events. This includes the design features of an installation that provide protection or the activation of emergency response plans in response to an event, e.g., fire suppression systems, temporary safe refuges.

With respect to the above noted risk reduction barriers, passive hardware barriers should be selected over active hardware barriers. Reliance on administrative barriers should be minimized. Where administrative barriers are required, they should be supplemented with associated documented processes and competency programs for the safety and environmentally critical tasks that persons are expected to perform. These tasks should be clearly linked to the risk assessment that identifies them as a measure and performance should be monitored periodically. A human factors analysis should also be performed.

d. Assumptions and Control Measures

For all major accidental event scenarios, the following should be assessed for each case, and include any associated interdependent systems:

- Effectiveness, availability and reliability of detection and communication systems.
- Availability and survivability of escape from every work area to the temporary safe refuge or evacuation station.
- Availability, habitability and survivability of temporary safe refuges and emergency response centres.
- Availability, habitability and survivability of all means of evacuation and rescue.
- Associated environmental consequences.

All assumptions and measures should be included in the Safety Plan, Environmental Protection Plan and Contingency Plan. Examples of assumptions include:

- Distribution of persons
- Training and competency of persons performing operations or maintenance tasks
- Standards of equipment installed
- Reliability of equipment (e.g., failure rate)
- Availability of equipment (including expected downtime)
- Survivability
- Functionality
- Interdependencies with other systems
- Process conditions, leak rates and duration
- Associated times to escape, evacuate and be rescued, etc.

Control measures should not be limited to the integrity of equipment, and should be interpreted to include identification of safety-critical processes under the management system, identification of safety-critical tasks (e.g., start-up, monitoring, operation, maintenance, emergency response) and identification of competency requirements for persons required to do those tasks.

Assumptions and control measures in relation to the integrity of safety-critical elements should be included in the performance standards referenced in section 160 of the *Framework Regulations*. This will also serve to provide clarity to the CA as part of the Certification Plan and the associated Scope of Work referenced in Part 3 of the *Framework Regulations*.

e. Risk Management

To ensure risks are maintained ALARP throughout the life cycle of an installation the following should also be implemented:

- Inspection, testing and maintenance of safety-critical elements should be carried out as referred to in sections 153, 154, 155, 158, 159, 160 and 161 of the *Framework Regulations*.
- Operator management (inclusive of partners, interest owners, etc.) should have an understanding of all risks, including major accidental events and the assumptions and control measures that have been put in place, and as a result, understand the impact of decisions being made (inclusive of budgetary and business decisions). A process should be put in place to inform management of the hazards and associated risks.
- As part of the orientation to the installation, all persons should receive an overview of the Safety Plan and the Environmental Protection Plan. In addition to OHS and environmental protection matters, all persons should be given an overview of the major accidental events that can occur, the safety-critical elements in place to provide protection, and the actions that need to be undertaken to ensure these systems are not inadvertently impaired. Any role-specific responsibilities with respect to safety-critical elements should be clearly articulated in the management system and explained during role-specific orientations and competency assurance programs.

- A comprehensive work permit system and simultaneous activity procedures should consider any assumptions made during risk assessments.
- Non-standard situations that may introduce new hazards not previously assessed or that may impact assumptions from existing risk assessments should be assessed.
- Information that may contribute to a major accidental event or impairments of safety-critical elements should be communicated during shift handovers, tour handovers or other meetings. The adequacy of interim measures in place should also be discussed.
- Emergency response and evacuation drills should demonstrate proficiency in dealing with major accidental events.
- Audits should include physical observation, discussion and review of records related to major accidental events to ensure assumptions and measures continue to be managed.
- Inspections and hazard identification processes should not just focus on OHS hazards but also include the identification of indicators related to major accidental events (e.g., hydrocarbon leaks, missing passive fire protection).
- Reviews of maintenance data should be undertaken to ensure the availability and reliability of safety-critical elements and compared to assumptions made in formal risk and reliability assessments.
- Reviews of incident data, including a review of the number of accidental hydrocarbon releases, spills, unauthorized discharges or toxic gas releases, should be undertaken and compared to assumptions made in formal risk assessments.
- Management of change processes where changes to operations, processes, persons, equipment, software, staffing levels, distribution of persons, etc., are assessed to ensure that the change and associated measures continue to maintain risks to ALARP and that underlying assumptions are not affected. These processes should also include temporary changes.
- Reviews of global incidents, latest global equipment data, lessons learned, experience, changes to regulatory requirements or standards, etc., should be undertaken to ensure risks are maintained ALARP.
- Risk assessments should be reviewed and updated periodically. Additional guidance is provided in *DNV-RP-G107 Efficient updating of risk assessments* and *NORSOK Z-013 Risk and emergency preparedness assessment.*
- A risk register and map to where or how the risk has been addressed as part of the management system should be maintained; however, this is not required if the hazards and measures are clearly identified in appropriate procedures in the management system.

f. Accepted Industry Standards

Additional guidance is provided in the following:

- *ISO 31000 Risk management - Guidelines.*
- *ISO 17776 Petroleum and natural gas industries – Offshore production installations – Major accident hazard management during the design of new installations.* While it states it is applicable to a production installation, it is referenced in the *IADC HSE Case Guidelines for Mobile Offshore Drilling Units* as a best practice. It should be noted that it does not cover the

risks associated with drilling or subsea systems, construction, commissioning, abandonment or security, so these risks will need to be considered separately.

- *ISO 31010 Risk management - Risk assessment techniques*.
- *ISO 13702 Petroleum and natural gas industries - Control and mitigation of fires and explosions on offshore production installations - Requirements and guidelines*.
- *ISO 15544 Oil and gas industries - Offshore production installations -- Requirements and guidelines for emergency response*.
- *IOGP Report 454 Human factors engineering in projects (in particular, Annex E).*
- *Energy Institute Guidance on Human Factors safety critical task analysis.*
- For MODUs, reference should also be made to the *IADC HSE Case Guidelines*.
- *NORSOK Z-013 Risk and emergency preparedness assessment* and *NORSOK S-001 Technical Safety.* It should be noted that these standards do not cover construction, commissioning and start-up of a facility during the operational phase, lifetime extension for a facility, assessment of major modifications, security or occupational health considerations, so these risks will need to be considered separately.
- *CSA Z1002 Occupational health and safety – Hazard identification and elimination and risk assessment and control* - this should be consulted for areas that overlap with OHS topics.
- Guidance on risk assessments for machinery management is covered in *API RP 691 – Risk-based Machinery Management.*
- *IMCA M115 Risk analysis of collision of dynamically positioned support vessels with offshore installations*.
- Flag state and classification society rules.
- If the operator wishes to use risk assessments based upon standards or requirements used in another jurisdiction, they should review those standards or requirements to ensure they are applicable and appropriate.

Section 109 – Monitoring Program for Physical and Environmental Conditions

109 (1) An operator must develop a monitoring program that involves the collection of data on physical and environmental conditions in sufficient quantities and at sufficient frequencies, and the retention of that data for sufficient periods, to
(a) support, during all works and activities, the identification of hazards and the assessment of the safety and environmental risks related to those hazards; and
(b) allow for the timely implementation of control measures to address the identified risks and, if necessary, of the contingency plan referred to in section 11.

Equipment

(2) For the purposes of subsection (1), the operator must ensure that the installation is equipped to observe, measure and forecast physical and environmental conditions, to record data on those conditions and to obtain from external sources any additional data on those conditions.

Program implementation and update

(3) The operator must ensure that the monitoring program is implemented and periodically updated.

Availability of data

(4) The operator must ensure that the data referred to in subsection (1) that may have an impact on safety and the protection of the environment is documented and provided to all persons that request it.

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a. Monitoring Program

The monitoring program should include all of the following:

- The environmental and physical conditions to be forecasted, measured and reported, including those that may have an impact on safety and protection of the environment considering physical and environmental conditions relevant to the design of the installation and its equipment. Refer to the requirements and associated guidance for sections 104 and 106 of the *Framework Regulations*.
- The requirements and associated guidance under section 42 of the *Framework Regulations*.
- The frequency of the generation of forecasts.
- The format of forecast reports, which should be easily understood by all parties (e.g., OIM, weather observers, personnel that need the information to conduct their work safely) and provide the information required for making operational decisions.
- The frequency at which forecast reports are disseminated to those that need them:
  - internally, to allow the operator to meet its duty pursuant to section 41 of the *Framework Regulations*; and
  - externally, to allow the operator to meet its duty pursuant to subsection 109(4) of the *Framework Regulations*.
- The frequency of the collection of observations of conditions.
- The format for reporting of observations of conditions, which should be easily understood by all parties and provide the information required for making operational decisions.
- The frequency at which reports of observations of conditions are disseminated to those that need them.
- The qualifications and number of personnel required to make forecasts or take observations;
- The requirements for equipment to forecast, observe and record physical and environmental conditions.
- The processes for inspection, testing and maintenance of that equipment.
- The process to verify the accuracy of observations.
- The process to verify the accuracy of forecasting with respect to observed conditions.

The operator should consult with service providers to determine any requirements associated with the provision of information to these service providers (e.g, helicopter service provider, search and rescue provider, support vessels).

b. Equipment

- With regards to the provision of equipment as required by subsection 109(2) of the *Framework Regulations,* the operator should consider:
  - *WMO Guide to Meteorological Instruments and Methods of Observation*
  - *Manual of Marine Weather Observations (MANMAR)*
  - *Manual of Surface Weather Observation Standards (MANOBS)*
  - *Manual of Standard Procedures for Observing and Reporting Ice Conditions (MANICE)*
  - *Canadian Aviation Regulations*
- Additional standards are referenced under sections 104 and 106 of the *Framework Regulations*. Refer also to the requirements and associated guidance for electrical systems under section 122 of the *Framework Regulations*.
- As this equipment is critical to the integrity of the installation, the monitoring equipment and procedures should be designed, installed and maintained to provide accurate information and be subject to a quality assurance program as referred to in section 100 of the *Framework Regulations*. Guidance on the provision of good quality meteorological data is available in *WMO Guide to Meteorological Instruments and Methods of Observation.*
- Inspection, testing and maintenance should be carried out as referred to in section 159 of the *Framework Regulations*.

c. Training

- Additional guidance on training and competency of aviation weather observers, marine weather observers and ice observers is provided in the COP TQOP.
- Forecasting of meteorological conditions should be done by a meteorologist, as should interpretation of meteorological data. While sea states may be forecasted by a meteorologist, forecasting of oceanographic conditions and interpretation of oceanographic data should be done by an oceanographer.

d. Reporting

- With respect to subsection 109(4) of the *Framework Regulations*:
  - Forecasts and ice management reports should be submitted to the *Regulator* and to other agencies that require this information.
  - For general distribution of marine observations, and in order to reduce transmission time and costs, weather reports should be coded in the WMO's form for this purpose: *FM 13–XIV Ext. SHIP, Report of surface observation from a sea station.* Guidance is provided in

the *Manual of Marine Weather Observations (MANMAR)*. A broader discussion of codes for transmission of meteorological data and other geophysical data is available in the *WMO Manual on Codes.*
   - To allow the *Regulator* to fulfill its mandate with respect to paragraph 20(1)(b) of the *Framework Regulations*, the operator should provide an accurate understanding of the operational limits of systems and equipment to the *Regulator* and submit accurate and timely forecasts of physical and environmental conditions such that the *Regulator* can fulfill that mandate. In NL, information should be shared with the *Regulator* in accordance with the *Code of Practice – Best Practice - Newfoundland and Labrador – Offshore Adverse Weather Communications Protocol.*
   - Refer to requirements for submission of daily reports, weekly reports and environmental reports to the *Regulator* as referred to in sections 182, 185, 197, 200, 201 and 207 of the *Framework Regulations*.

Section 110 – Inspection, Monitoring, Testing and Maintenance

110 An operator must, for the purpose of facilitating the inspection, monitoring, testing and maintenance of an installation, ensure that
(a) relevant areas are clearly marked and identified;
(b) there is safe access to those areas;
(c) in the case of an installation that is not intended to be periodically drydocked, there are means for carrying out an on-location inspection of the hull and underwater components;
(d) there is safe access to subsea equipment; and
(e) the installation is otherwise designed and equipped to permit those activities to be carried out.

- With respect to paragraphs 110(a) and (b) of the *Framework Regulations,* a safe means of access to areas should be provided for inspection, monitoring, testing and maintenance. Providing temporary access to equipment via scaffolding, winches, cranes, portable ladders, etc., may introduce other hazards and may result in additional time to conduct these activities, so installations should be designed with this in mind.
- With respect to paragraph 110(d) of the *Framework Regulations*, subsea equipment should be arranged to permit safe accessibility for operation, maintenance, inspection and testing.
- Consideration should be given to applying RPAS and other similar technologies to supplement inspection, monitoring, testing and maintenance activities when it is safe and practicable to do so.

Section 111 - Materials for Installations

111 (1) An operator must ensure that the materials used in an installation are
(a) fit for the purposes for which they are to be used and suitable for the conditions to which they may be subjected, including any foreseeable emergency situation;
(b) non-combustible, unless essential properties are available only in materials that are combustible or the use of combustible material will not increase the risk to safety; and
(c) selected to ensure that, in the case of fire or explosion, their use will not increase the risk to safety in the area of the fire or explosion or in adjacent areas, including by exposing persons to toxic fumes or smoke.

Definition of non-combustible

(2) In this section, non-combustible means, in respect of material, material that does not burn or give off flammable gases or vapours in sufficient quantity for self-ignition when heated to 750°C.

a. General

- Refer to the requirements and associated guidance for designing for physical and environmental conditions, materials used in the design and construction of installations, risk assessments, asset integrity and corrosion management under sections 98, 104, 105, 106, 107, 108, 153 and 155 of the *Framework Regulations*.
- Refer to the requirements and associated guidance for fire areas, housekeeping, structural safety and hazardous substances under section 26 and Parts 12, 17, 21 and 31 of the *OHS Regulations*, respectively.
- This is interpreted to apply to materials used for:
    - the design, construction and repair of equipment, structures, piping, floors, guardrails, insulating materials, ceilings, linings, primary deck coverings, surface finishes and other equipment such as scaffolding, dunnage, etc.; and
    - furnishings, mattresses, curtains, bedding, etc.

- Associated guidance is provided in the following:
    - SOLAS, MODU Code, *IMO International Code for Application of Fire Test Procedures* and any associated IMO resolutions or circulars
    - Flag state and classification society rules
    - *NORSOK S-001 Technical Safety*
    - *NFPA 1 – Fire Code* and *NFPA 101 Life Safety Code*

b. Use of Plastic and Epoxy in Design

- For the use of FRP, GRP or GRE, it should be noted that if the material may be subject to a hydrocarbon fire or is required to survive a hydrocarbon fire for the time necessary to meet its required survivability time according to its associated performance standard, then additional fire testing may be required. The use of these materials would have to be demonstrated to provide an equivalent level of safety during an emergency and following exposure to heat or fire. Any assumptions or measures from risk assessments to ensure integrity should be managed.
- In addition to the requirements and guidance under section 105 of the *Framework Regulations*, refer to the following:
  - *NORSOK M-001 Materials Selection*
  - *DNV-ST-C501 Composite Components*
  - *ABS Rules for Building and Classing Facilities On Offshore Installations (Appendix 1-3)*
- o FRP/GRP grating or guard-rails that are intended to support a load should not be installed in primary or secondary escape or evacuation routes, or in areas that are subject to high heat, have a moderate to high risk of fire, or have a drop height of greater than 3 m unless it can be demonstrated that the gratings will work as intended in an emergency. It is also noted that the test methods prescribed in some widely accepted guidance documents (such as *USCG PFM 2-98)* have either been based on non-hydrocarbon fire scenarios or have resulted in gratings with a fire resistance that is not equivalent to steel. In addition to the requirements and guidance under section 107 of the *Framework Regulations*, refer to *Health and Safety Executive – Safety Alert HID 2-2012 – Possible Failure of Fire Resistant Composite Deck Gratings, Health and Safety Executive RR950 – Preliminary fire testing of composite offshore pedestrian gratings*. Gratings and guard-rails must also meet the requirements of the *OHS Regulations* for structural safety as noted above. *ASTM F3059 Standard Specification for Fiber-Reinforced Polymer (FRP) Gratings Used In Marine Construction and Shipbuilding* should also be consulted; however, this standard does not address hydrocarbon pool or jet fire exposures and does not address the ability of the grating to support equipment or persons during or after a fire exposure.
- FRP/GRP piping or tanks that are safety or environmentally critical should be rated for the types of fires expected in the area in which it is installed and should be designed, constructed and installed to reduce the possible hazard for static electricity build-up.
- If FRP/GRP piping is used in a moderate to high flame spread area it should be properly assessed and have measures in place, such as appropriate fire detection and suppression systems.
- o Additional guidance is provided in *ISO 14692-3 Petroleum and natural gas industries - Glass-reinforced plastics (GRP) piping – Part 3: System Design.*
- Refer also to the requirements and associated guidance for pressure systems under section 135 of the *Framework Regulations.*

c. Storage and Use of Combustible Materials

- Refer to the requirements and associated guidance for hazardous substances under section 45 of the *Framework Regulations* and Part 31 of the *OHS Regulations*.
- The amount of combustible material used on a drilling or production installation should be kept to a minimum and should include the following:
  - A list of the amount and location of long-term combustibles (e.g., dunnage, scaffolding, grating on deck to prevent slips) onboard on an installation should be maintained and records of its ongoing inspection and maintenance should be available. Procedures should be in place for the storage, inspection and management of combustible material. With respect to the use of wood:
    - Wooden scaffolding planks offer advantages such as lower probability of sparking, and lower probability of damaging equipment. However, the fire treating for wooden scaffolding must be maintained. If the coating is damaged it should be removed from service. Wooden scaffolding should not be stored in hazardous areas (e.g., process areas), in areas that have not been designed to store combustible materials (e.g., no active fire detection or fire suppression systems) or on open decks where it is subject to physical and environmental conditions. Also, wooden scaffolding planks should also not be used as a permanent arrangement.
    - Wooden dunnage (on drill floors and for crane rests) offers advantages such as lower probability of sparking, lower probability of damaging equipment and for flooring, providing a non-skid surface. However, in areas exposed to drilling fluid, the wood may absorb oil and other flammable substances and increase its risk of ignition. If it is used, it should have a surface impervious to moisture and have fire treating. The surface should be inspected, maintained and replaced when deterioration is noted.

d. Routine Inspections

Within accommodations and other public spaces, inspections should seek to identify and remove any potential fire hazards such as excessive storage of combustibles (e.g., paper, recycling), overloading of extension plugs, damaged electrical cords, electrical equipment left charging on bedding or other combustible material, etc.

Section 112 - Passive Fire and Blast Protection

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112 (1) An operator must ensure that an installation is designed and constructed with passive fire and blast protection.

Design of passive fire protection

(2) The design of the passive fire protection must
(a) not take into account the cooling effect from active firefighting equipment; and

(b) take into account the need to inspect and maintain the passive fire protection components and the structures, divisions and the equipment they are intended to protect.

Divisions

(3) The operator must ensure that the installation is divided such that spacing and barriers protect against accidental events and loads identified in the risk assessment conducted under subsection 107(1) or mitigate their effects.

Barriers — safety plan and environmental protection plan

(4) The operator must ensure that barriers are designed, arranged, installed and maintained in accordance with the measures referred to in clauses 9(2)(b)(v)(C) and 10(2)(b)(v)(C) that are described in the operator's safety plan and environmental protection plan, respectively.

Barriers - requirements

(5) Barriers must be designed, arranged, installed and maintained to
(a) contain fire, smoke, explosions and hazardous gas and prevent their effects from spreading into adjacent areas;
(b) protect persons from fire, smoke and explosions for the time necessary to enable them to escape to a temporary safe refuge;
(c) maintain for the necessary time, as determined on the basis of the safety studies referred to in section 116, the integrity of temporary safe refuges and of associated facilities that allow for communication, command, monitoring, control and evacuation against the effects of fire or explosion;
(d) protect safety-critical elements and equipment that are to remain operational in the event of an emergency from failure or malfunction caused by the effects of fire or explosion; and
(e) maintain the installation's structural integrity against the effects of fire or explosion for the time necessary to safely evacuate all persons.

Barriers — level of protection

(6) The level of fire and blast protection that each barrier must provide is to be based on the results of the risk assessment conducted under subsection 107(1).

Barriers — penetrations and openings

(7) A barrier must not have any penetrations or openings unless
(a) the penetration or opening is necessary for the functionality of the installation;
(b) the barrier is equipped to maintain its overall fire and blast integrity despite the penetration or opening; and
(c) if there is a means of closing the penetration or opening, that means can be activated automatically or from outside the space being protected.

Barrier components

(8) The operator must ensure that barrier components are certified by a competent third party.

Bulkheads — production installation

(9) Unless the other combined features of a production installation can be demonstrated to provide at least the same level of protection, the operator must ensure that the following bulkheads are capable of preventing the passage of smoke and flame and of limiting the temperature rise on the unexposed face of the bulkhead to an average increase of 139° C and a maximum increase of 180° C above the initial temperature following 120 minutes of exposure to a hydrocarbon fire:
(a) those external bulkheads of the temporary safe refuges, main control centre, control stations, accommodations areas, embarkation stations and evacuation points, other than aircraft landing areas that face production areas or wellheads; and
(b) the bulkheads that segregate the wellhead and processing areas from other areas of the installation.

Classification society rules

(10) The operator must ensure that the passive fire and blast protection for an installation that does not hold a valid certificate of class issued by a classification society is at least equivalent to the protection required under the rules of a classification society for a mobile offshore drilling unit.

General

- Refer to the requirements and associated guidance under section 26 of the *OHS Regulations*.
- Refer to the requirements and associated guidance for materials for installations, asset integrity and electrical and associated software systems for automatic functions for fire doors and fire dampers under sections 98, 111, 122, 123, 124, 125, 153 and 169 of the *Framework Regulations*.
- The outcomes and measures inherent from the risk assessments conducted under section 107 of the *Framework Regulations* should include the following:
    - The layout of the installation and equipment to provide inherent safety.
    - The design of equipment and structures to provide safety, including protection for valves, cables, etc.
    - The amount and type of passive fire protection and blast protection necessary to maintain the integrity of structural supports (e.g., primary, secondary), decks, fire divisions, safety-critical equipment and associated support systems. This should include the protection of escape/evacuation routes, life-saving appliances and control stations (such as areas

where critical operations may be performed such as wire line units, mudlogging, coiled tubing units, etc., for when no redundancy is provided).
- The design and continued integrity of components of fire divisions, such as doors, windows, glass walls, floors, penetrations (including piping, cables and ductwork), draft stops, joints, drains and dampers.
- The provision of bunding around equipment, the associated open and closed hazardous drain systems and fire seals.

- Materials for passive fire protection should be selected such that they do not generate toxic fumes when heated and pose a risk to persons.
- Hydrocarbon piping should not be routed within electrical or instrumentation rooms, control rooms, accommodations, temporary safe refuges or other areas containing safety-critical equipment unless it is to provide a source of fuel for that equipment. If this cannot be achieved, additional measures should be implemented to reduce the risk. In addition, routing of hydrocarbon piping should consider the risks associated with being placed adjacent to the above noted areas.
- The addition of permanent or temporary equipment (including pipes, instrumentation, scaffolding, hoardings, etc.) in an area, the reduction of passive fire or blast protection, an increase or change in materials processed, stored or used in an area or the increase of persons present in an area may have an impact on the associated risk assessments that have been undertaken. These changes should be assessed through a formal management of change process to determine if the existing measures implemented within this section will continue to be appropriate following a change.
- If temporary openings are required in fire rated divisions (e.g., removal of hatches, running new cables through transits, securing doors open), this work should be undertaken under a work permit and managed such that it does not pose a risk.
- Flammables and combustibles should only be stored in areas purposely designed to contain these materials.
- With respect to subsection 112(9) of the *Framework Regulations*:
  - "processing areas" is interpreted to include those areas of the installation that process hydrocarbons (i.e., separation, compression, treatment, injection, disposal) and does not include cargo areas (e.g., cargo spaces, pumprooms, cofferdams adjacent to cargo tanks); and
  - "wellhead" and "processing areas" do not require separation from each other using H-120 fire divisions, but the level of protection provided between those areas should be based on the risk assessment.
- With respect to subsection 112(10) of the *Framework Regulations*, the latest version of the rules of the classification society should be referred to and if changes are made, a review should be undertaken to identify impacts on design, operation, inspection, etc.

Standards

- Additional guidance is provided in the following:
  - SOLAS, MODU Code, any associated IMO resolutions and circulars, flag state requirements and classification society rules with the following notes:

- The assessment of explosions, hydrocarbon jet fires and pool fires and associated measures are not included in SOLAS or the MODU Code, so additional assessment should be undertaken.
- Classification society rules specify requirements that may not be in compliance with the regulations (e.g., subsection 112(9) of the *Framework Regulations*) or be suitable to meet the outcomes of the risk assessment. As a result, additional assessment should be undertaken. In addition, unless the fire and explosion analysis demonstrates that a higher level of protection is required:
    - Control stations (outside of the accommodations and temporary safe refuges), fire suppression supply system rooms, emergency power supply system rooms and other rooms that perform safety-critical functions should be separated from other areas by A-60 divisions to ensure their continued function. Critical areas that face production areas or wellheads must consider the requirements of paragraph 112(9)(a) of the *Framework Regulations*.
    - Accommodations and temporary safe refuges should be separated from other areas by A-60 divisions to ensure their continued function.
    - Areas of potentially higher fire risk (e.g., galleys, laundry rooms, storage rooms, electrical rooms) should be segregated from lower risk areas with barriers in place that will prevent the passage of fire and smoke (e.g., A-rated barriers as opposed to B-rated barriers) and should be protected by an automatic fire detection system and automatic fire protection system as determined through the risk assessment. Some other considerations for galley areas:
        - They should have at least an A-60 fire rated barrier or other measures that provide an equivalent level of safety.
        - Any openings in the barrier (e.g., doors, shutters) should be kept closed when not in use or be equipped with automatic closing devices that are tested periodically.
        - When equipped with automatic closing devices, signage and instructions to not block these openings should be put in place.
        - A manual means should be provided to close these barriers in the event the automatic closing device does not work.
    - Areas that have potential to affect several areas (e.g., elevators, stairways, corridors, ventilation, cable or piping trunks) should be separated from other areas with an A-rated barriers. Combustibles and flammables should not be stored in these areas.
    - Areas that are required to remain in operation in the event of an emergency, such as emergency response operations centres, should have A-rated barriers that will prevent the passage of fire and smoke.
    - Openings in fire rated divisions (e.g., fire doors) should be kept closed at all times unless they are equipped with automatic closing devices. Signage should be installed to communicate this requirement.
- As classification society rules do not require that "H" ratings and blast divisions be indicated on installation drawings, consideration should be given to updating installation drawings to include this information.

    - Additional notes on associated definitions used in the above noted codes and rules are as follows:
        - The definition of "machinery space of category A" does not include all internal combustion engines, gas turbines, engine-driven power generators, any pump used for transfer of fuel or hydrocarbons and every storeroom containing paint, oil, any gaseous substance or other flammable material. Additional consideration should be provided for these areas.
        - The definition of “accommodation space” is not the same as the definition of “accommodations area” in the *Framework Regulations* and does not include meeting rooms, arrival and departure lounges and emergency response operations centres. Additional consideration should be provided for these areas.
- *ISO 19901-3 Oil and gas industries including lower carbon energy – Specific requirements for offshore structures – Part 3: Topsides Structure.*
- *ISO 13702 Oil and gas industries - Control and mitigation of fires and explosions on offshore production installations - Requirements and guidelines,* with the following notes:
    - Although the guidance applies mainly to production installations, it can be applied to any type of installation.
    - The hazards associated with subsea installations or MODUs are not included but should be considered, as applicable.
    - The application of typical fire integrity for barriers between areas (e.g., accommodation blocks, non-hazardous utility areas, wellhead areas, drilling areas, process areas and control stations) that is listed in Table C.5 may result in a noncompliance with subsection 112(9) of the *Framework Regulations*.
    - Combined loading scenarios (concurrent hydrocarbon pool and jet fires) should be considered and accounted for in the design.
- *NORSOK S-001 Technical Safety*, however, it should be noted that recommendations for fire integrity for barriers between areas (e.g., accommodations) may result in a noncompliance with subsection 112(9) of the *Framework Regulations*.
- *NFPA 1 – Fire Code* and *NFPA 101 Life Safety Code* contain guidance for the design, performance, inspection, testing and maintenance of components of fire divisions, such as fire doors (e.g., *NFPA 80 Standard for Fire Doors and Other Opening Protectives* and *NFPA 105 Standard for Smoke Door Assemblies and Other Opening Protectives)*, windows, glass walls, penetrations (including piping, cables and ductwork), draft stops, joints, drains and dampers, and other considerations for selection of equipment and adoption of practices to reduce the risk of fire.
- *API RP 2FB Recommended Practice for the Design of Offshore Facilities Against Fire and Blast Loading,* however, particular care should be taken to ensure that the heat load from pool and jet fires is based on design rates and pressures as some codes may underestimate the heat load.
- *NFPA 69 Standard on Explosion Prevention Systems.*
- Appendix F of *API RP 14G Recommended Practice for Fire Prevention and Control on Fixed Open-Type Offshore Production Platforms* contains recommended practices for visual inspection and repairs to passive fire protection.

Section 113 - Hazardous and Non-Hazardous Areas

113 (1) An operator must ensure that the boundaries between all hazardous areas and non-hazardous areas on an installation are delineated.

Classification of hazardous areas

(2) The operator must ensure that, following the conduct of the risk assessment under subsection 107(1), each hazardous area is classified according to an internationally recognized, comprehensive and documented classification system.

Separation of areas

(3) The operator must ensure that hazardous areas of different classifications are separated from one another and from non-hazardous areas.

Direct access and openings

(4) The operator must ensure, if practicable, that there is no direct access or other opening between hazardous areas and non-hazardous areas and between hazardous areas of different classifications or, if that is not practicable, that any direct access or opening between those areas is minimized and is designed to prevent uncontrolled air flow between them.

Piping systems

(5) The operator must ensure that piping systems are designed to ensure that there is no direct conduit between hazardous and non-hazardous areas and between hazardous areas of different classifications.

General

- Refer to the requirements and associated guidance for hazardous areas under section 26 of the *OHS Regulations*.
- Refer to the requirements and associated guidance for ventilation, electrical systems and mechanical systems under sections 114, 122 and 136 of the *Framework Regulations*.
- This section applies to the classification of locations for both temporarily and permanently installed electrical equipment.
- There are other considerations for equipment (e.g., mechanical, friction) or activities (e.g., transitory operating states) that may be a potential source of ignition and should be taken into account. Refer to the requirements and additional guidance under section 115 of the *Framework Regulations*.

- Refer to the requirements for hazardous area drawings in section 157 of the *Framework Regulations*.

Standards

- Additional guidance on the classification of hazardous areas is provided in the following:
    - For flammable liquid, gas or vapour hazards refer to *IEC 60079-10-1 Explosive Atmospheres – Part 10-1: Classification of areas — Explosive gas atmospheres* (which includes flammable mists) or other similar standards.
    - For combustible dust, ignitable fibres or flyings refer to *IEC 60079-10-2 Explosive atmospheres – Part 10-2: Classification of areas - Explosive dust atmospheres* or other similar standards.
    - Drilling and production installations should also follow guidance for classification of areas resulting from the presence of flammable liquids, flammable gases or vapors, or combustible liquids as described in:
        - *API RP 500 Recommended Practice for Classification of Locations for Electrical Installations at Petroleum Facilities Classified as Class I, Division I and Division 2* or *API RP 505 Recommended Practice for Classification of Locations for Electrical Installations at Petroleum Facilities Classified as Class I, Zone 0, Zone 1, and Zone 2*. However, it should be noted that:
            - The classification of hazardous areas is done for the purposes of ensuring that electrical equipment installed in an area is rated for operation in that area under normal operating conditions, which means during normal operations, the equipment is not a source of ignition. The classification of hazardous areas in accordance with either of these practices does not consider transitory, abnormal or emergency conditions (e.g., release of hydrocarbon gas or a blowout). Once a hazardous environment is detected, systems should be designed to shut down and isolate any piece of equipment that is not rated for operation in that environment. Refer to the requirements and associated guidance for ignition prevention and emergency shutdown systems under sections 115 and 133 of the *Framework Regulations*.
            - Neither of these practices apply to classification of locations containing combustible dust, flammable mist or ignitable fibres or flyings. Refer to the IEC standards noted above.
        - MODUs should refer to the MODU Code
        - All installations should refer to *IEC 61892-7 Mobile and Fixed Offshore Units - Electrical Installations - Part 7: Hazardous area.*
        - Floating production platforms should refer to *IEC 60092-502 Electrical Installations in Ships – Part 502: Tankers – Special features*.
        - Floating installations should also refer to *Transport Canada Publication TP 127E Ships Electrical Standards for Marine Systems*.

Section 114 – Ventilation Systems

114 (1) An operator must ensure that any enclosed hazardous area on an installation is ventilated such that
(a) air is replaced at a rate sufficient to prevent hazardous gas accumulations in the enclosed hazardous area;
(b) all air entering the enclosed hazardous area is from a non-hazardous area;
(c) the air exhausted from the enclosed hazardous area does not increase the hazard level in another enclosed hazardous area or create a hazard in an enclosed non-hazardous area; and
(d) the ventilation system for the enclosed hazardous area is separate from the ventilation system for any non-hazardous area.

Mechanical ventilation system

(2) If a mechanical ventilation system is used for the purposes of subsection (1), the operator must ensure that the air in the enclosed hazardous area is maintained at a pressure that is lower than the pressure of any adjacent non-hazardous area or any adjacent hazardous area that is classified as less hazardous.

Air exhaustion from enclosed hazardous area

(3) The operator must ensure that all air exhausted from an enclosed hazardous area is vented to an outdoor area that, were it not for the vented air, would be a non-hazardous area or a hazardous area that would be classified as no more hazardous than the enclosed hazardous area.

Ventilation pressure differential and functionality

(4) The operator must ensure that measuring devices are installed that will monitor any loss of ventilation pressure differential and any loss of functionality of each ventilation system for a hazardous area and that will, no more than 30 seconds after such a loss occurs, activate audible and visual alarms at the control points from which the system is monitored.

Positive overpressure relative to atmospheric pressure

(5) The operator must, in respect of the main control centre and all accommodations areas on an installation, ensure that
(a) they are maintained at a positive overpressure relative to atmospheric pressure;
(b) all of their external doors that provide a primary means of access to them are equipped with airlocks; and
(c) all of their other external doors are equipped with airlocks or other means of maintaining and monitoring positive overpressure relative to atmospheric pressure.

Power shut-off for mechanical ventilation system

(6) The operator must ensure that the power source for a mechanical ventilation system that serves a hazardous area, a work area in a non-hazardous area or an accommodations area is capable of being shut off from the control station and from a position that is outside the area being ventilated and that will remain accessible during any fire that may occur within that area.

Inlets and outlets of ventilation systems

(7) The operator must ensure that the main inlets and outlets of all ventilation systems are capable of being closed from a position that is outside the area being ventilated and that will remain accessible during any fire that may occur within that area.

Ventilation system in non-hazardous area

(8) The operator must ensure that any ventilation system that serves a non-hazardous area is equipped with emergency devices in the event of a mechanical ventilation failure or the detection of hazardous gas, including
(a) measuring devices to monitor any loss of ventilation pressure differential;
(b) audible and visual alarms;
(c) an automated isolation device to prevent hazardous gas from entering the non-hazardous area; and
(d) a device to remotely seal the non-hazardous area — including inlets and outlets of all ventilation systems — from the control station and from a position outside the non-hazardous ventilated area that will remain accessible during any fire that may occur within the area.

General

- Refer to the requirements and associated guidance under subsection 65(4), paragraphs 23(c), 57(1)(d), 133(1)(h) and 157(1)(d) and Part 16 of the *OHS Regulations*.
- Refer to the requirements and associated guidance for physical and environmental conditions, risk assessments, hazardous and non-hazardous areas, ignition prevention, electrical systems, control and monitoring systems, fire and gas detection systems, emergency shutdown systems, mechanical systems and asset integrity under sections 98, 104, 106, 107, 110, 115, 122, 123, 124, 125, 132, 133, 136 and 153 of the *Framework Regulations.*
- The placement of additional equipment, changes in equipment, changes in process or addition of persons in an area, whether it be permanent or temporary, may have an impact on the associated risk assessments that have been undertaken and the effectiveness of natural ventilation or forced ventilation systems that have been provided. Changes should be assessed through a formal management of change process to determine if existing measures implemented within this section will continue to be appropriate following a change.

- Any temporary or third party equipment or modules should also meet the requirements of the *Framework Regulations* and *OHS Regulations* as referenced above.
- Dampers should close quickly enough to prevent the ingress of any gases or smoke and to minimize pressure losses, if possible. In areas required to maintain a safe environment for persons or for the operation of unrated equipment, dampers should be placed far enough downstream from gas, smoke and H_2S detectors and should activate before the contaminant reaches the damper.
- Emissions from ventilation outlets must meet the limits of any discharge as described in the Environmental Protection Plan and meet any commitments or conditions under the *Development Plan* and associated Environmental Assessments and Impact Assessments.
- Ventilation outlets exhausting hazardous substances should not be placed in areas where persons are present, such as walkways.
- With respect to subsection 114(5) of the *Framework Regulations*, if service or machinery spaces can generate hazards for the main control centre and accommodations area (e.g., CO, smoke), the doors between those areas and the service or machinery spaces should have either an airlock or another means of maintaining and monitoring the overpressure installed.
- With respect to paragraphs 114(8)(c) and (d) of the *Framework Regulations*, an "automated isolation device" refers to the shutdown of equipment that is drawing the air into the non-hazardous area, whereas "a device to remotely seal the non-hazardous area" refers to a damper.

Standards

- In addition to the standards referenced in the *OHS Regulations*, additional guidance is provided in the following:
  - *ISO 13702 Petroleum and natural gas industries - Control and mitigation of fires and explosions on offshore production installations - Requirements and guidelines*.
  - *ISO 15138 Petroleum and natural gas industries – Offshore Production Installations - Heating, ventilation and air-conditioning*. This document also contains guidance on temperature, humidity, noise, natural ventilation and ventilation for different areas, performance expectations and requirements for individual components such as fire dampers, airlocks, etc.
  - *NORSOK S-001 Technical Safety*. This document also contains guidance on ventilation actions associated with different fire and gas detection scenarios in various locations and suggested response time for closing of HVAC inlet dampers.
  - *IEC 60079-13 Explosive atmospheres – Part 13: Equipment protection by pressurized room "p" and artificially ventilated room "v"*. This document provides requirements for rooms used to protect internal equipment when the room is in a hazardous area (e.g., local electrical rooms) or if the room contains a source of hydrocarbon release and is meant to be accessed by persons regularly (e.g., cargo pump room).
  - SOLAS, MODU Code and associated IMO resolutions or circulars contain guidance for these systems; however, the following should be noted:
    - As IMO requirements only apply to equipment associated with marine operations, it does not cover the hazards or systems associated with non-marine operations.

    - Compliance to IMO requirements alone does not address compliance to the *Framework Regulations* and *OHS Regulations* as noted above.
    - Particular attention needs to be paid to the risk assessments to ensure that appropriate executive actions to stop HVAC fans and close dampers occur upon gas detection to reduce risk in all areas.
  - Flag state and classification society rules should also be applied, but compliance to these rules alone does not address compliance to the *Framework Regulations* and *OHS Regulations* as noted above.
  - Specific aspects for ventilation systems are included in the API and IEC standards referenced under section 113 of the *Framework Regulations*.
  - Refer to requirements and associated guidance for operations and maintenance of these systems under sections 153, 156, 157 and 158 of the *Framework Regulations*.

Section 115 - Ignition Prevention

115 (1) In order to prevent the ignition of flammable, combustible or explosive substances on an installation, an operator must ensure that measures are implemented to prevent the uncontrolled release or accumulation of those substances, including by ensuring that materials and equipment are properly arranged.

Design — systems and equipment

(2) The operator must ensure that any system or equipment that is to be used in a hazardous area is designed to control ignition sources and to prevent fire and explosions in that area, taking into account the area's classification under subsection 113(2).

Risk assessment

(3) For the purposes of meeting the requirements under subsections (1) and (2), the operator must ensure that any control measures identified in the risk assessment conducted under subsection 107(1) are implemented.

Other requirements — equipment

(4) The operator must ensure that any equipment located in a hazardous area is rated for use in that area and is installed, ventilated and maintained to ensure safe operation.

Safe distance operation

(5) The operator must ensure that any equipment that is operated in a non-hazardous area is operated at a safe distance from any flammable, combustible or explosive substances and is,

unless it is rated for use in a hazardous area, equipped with an automatic and manual means of deactivation in the event of fire or hazardous gas detection.

Equipment in the event of an emergency

(6) The operator must ensure that any equipment that is located in a non-hazardous area and that is to remain in service in the event of an emergency associated with a gas release is rated for use in a hazardous area and is installed, ventilated and maintained to ensure safe operation.

Cargo tank

(7) The operator must ensure that
(a) the gas mixture inside a cargo tank is maintained outside the explosive limits; and
(b) the systems associated with the cargo tank are designed to
(i) prevent fire, gas or explosion hazards during all operating modes through the use of sufficient control measures, including alarms, and through redundancies in those measures; and
(ii) ensure that affected persons are made aware when the systems become impaired.

Work permit

(8) A work permit is required for all hot work carried out on an installation.

Safe distances

(9) The work permit for hot work must set out safe distances to be maintained between the hot work and any well or any flammable, combustible or explosive substance.

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a. General

- Refer to the requirements and associated guidance for hazardous and non-hazardous areas in section 113 of the *Framework Regulations*.
- With respect to subsection 115(4) and (6) of the *Framework Regulations*, “ventilated” is interpreted to mean natural or artificial ventilation in the area in which the equipment is installed and is not interpreted to mean ventilation by a purge or pressurization system.
- With respect to subsection 115(7) of the *Framework Regulations*, “cargo tank” is interpreted to include cargo tanks on FPSOs and cargo storage areas on other types of platforms.

b. Ignition Sources

The use of equipment or the conduct of certain activities may cause ignition of an explosive atmosphere. Ignition sources can either be onboard an installation or on an adjacent support craft, installation or vessel. Potential sources of ignition include the following:

- Electrical equipment, including temporary or portable equipment that is not rated for operation in a hazardous area or an explosive atmosphere. Refer to requirements and guidance under section 122 of the *Framework Regulations*.
- Hot work activity, which includes any work or activity that involves the use of or is likely to produce a fire, spark or other source of ignition (e.g., grinding, chipping, welding, burning, drilling, riveting). Refer to requirements and associated guidance under Part 26 of the *OHS Regulations*.
- Open flames and flaring.
- Hot emissions from exhausts or vents.
- Heating elements (e.g., heaters, radiators) and unprotected fired equipment (e.g., boilers).
- Hot surfaces of equipment, piping and exhaust pipes.
- Thermite sparking.
- Rotating machinery and internal combustion engines - refer to requirements and guidance under section 136 of the *Framework Regulations*.
- Mechanical sparks generated from moving parts of equipment or from associated operations (e.g., cranes, fans, draw works, anchor windlasses, chain lockers, dropped objects).
- Static electricity (e.g., fueling, spraying of liquids, shot blasting, steam cleaning, vacuuming, filling or transport of liquids onboard or to/from a support craft or tanker). Refer to the requirements and guidance under paragraph 157(1)(i) of the *OHS Regulations*.
- Portable equipment, such as tools, shovels, etc., that can generate a spark when used.
- Radio frequency energy.
- Explosives - refer to the requirements and guidance under Part 30 of the *OHS Regulations*.
- Radiation energy - refer to the requirements and guidance under Part 31 of the *OHS Regulations*.
- Charging of batteries.
- Adiabatic compression and shock waves.
- Chemical reactions (e.g., incompatible materials, pyrophoric substances).
- Stray electric currents.
- Cathodic corrosion protection.
- Lightning.

c. Measures

- Based on the potential, additional measures may need to be implemented. Some typical examples of measures that should be implemented to reduce the risk of ignition include:
  - Containing and draining of flammable liquid spills to a safe location.
  - Reducing the amount of combustible or flammable material or substances.
  - Storing materials and substances in designated locations and considering issues of incompatibility with other substances.

- Venting all hazardous gases to a closed system for discharge to a safe location.
- Selecting equipment with an appropriate temperature rating.
- Using insulation that is protected against oil penetration in areas where combustible or flammable liquids may spill.
- Using cooling water systems, water spray systems, inerting or purging systems to prevent sparking of mechanical equipment.
- Installing spark arrestors on exhausts.
- Installing flame arrestors.
- Inerting of tanks containing flammable or combustible liquid or gas or other means of managing the interface above the stored liquid or gas.
- Designing areas where ignition sources are being created with design measures to prevent, detect (e.g., fire and gas detection systems) and mitigate (e.g., shutdown device, tie in to emergency shutdown system) hazardous gases from entering during an emergency.

- Consideration should also be given to the inspection, testing and maintenance procedures and auditing procedures to verify the integrity of equipment and associated controls.

d. Standards

Additional guidance on ignition prevention is provided in the following:

- SOLAS Chapter II-2, Regulation 4 – Probability of Ignition.
- MODU Code, Section 6.7 applicable to drilling installations.
- *ISO 13702 Petroleum and natural gas industries – Control and mitigation of fires and explosions on offshore production installations,* which can be applied to all types of installations.
- *API RP 14J Recommended Practice for Design and Hazards Analysis for Offshore Production Facilities,* which can be applied to all types of installations.
- *ISO 80079-36 Explosives atmospheres – Non-electrical equipment for explosive atmospheres – Basic methods and requirements.*
- *NFPA 30 Flammable and Combustible Liquids Code.*
- *NFPA 69 Standard on Explosion Prevention Systems*, which includes guidance for inerting or enrichment of an environment.
- *NFPA 400, Hazardous Materials Code.*
- Flag state and classification society rules. With respect to production installations, also consider guidance issued for tanker operations by the ICS.

e. Equipment in the event of an emergency

With respect to subsection 115(6) of the *Framework Regulations*:

- As major gas release scenarios could result in a gas cloud larger than the defined hazardous area classification in an outdoor area, a risk assessment should be conducted on all equipment required to stay live in the event of an emergency shutdown (e.g., navigation lights and sound signalling, communication systems, fire and gas detection, lighting) to determine whether it needs to be rated for Zone 0, 1, 2 or equivalent. The level of protection selected should be based on factors such as the equipment's criticality, continued availability and redundancy. Any other equipment that is not required or has no alternative means of protection to prevent it from being a source of ignition, should be shut down as part of the emergency shutdown system referred to in section 133 of the *Framework Regulations*.

- It is interpreted that this section does not apply to enclosed non-hazardous areas that have other measures in place to protect internal equipment from being a source of ignition.

f. Hot Work

With respect to subsection 115(8) of the *Framework Regulations*, refer to the requirements and associated guidance provided under Part 26 of the *OHS Regulations*. With respect to subsection 115(9) of the *Framework Regulations*, refer specifically to the definitions and to section 13 of *CSA W117.2 Safety in Welding, Cutting and Allied Processes*, which has been incorporated by reference in the *OHS Regulations*, as this includes the safe distances to be maintained for certain processes. The safe distances for activities outside of this standard should be determined from the risk assessment.

Section 116 – Means of Escape, Evacuation and Rescue

116 An operator must ensure that an installation is equipped with a safe means of escape, evacuation and rescue, taking into account the results of the risk assessment conducted under subsection 107(1) and comprehensive and documented safety studies.

- Refer to the requirements and associated guidance for emergency response equipment and escape under Parts 5, 6, 8, 11 and 17 of the *OHS Regulations*.
- Refer to the requirements and associated guidance for physical and environmental conditions, design for intended use and location, risk assessments, passive fire and blast protection, hazardous and non-hazardous areas, ventilation systems, ignition prevention, temporary safe refuges, life-saving appliances, electrical systems, control and monitoring systems, emergency electrical power, communication systems and emergency shutdown systems under sections 98, 104, 105, 106, 107, 108, 110, 112, 113, 114, 115, 117, 118, 119, 122, 123, 124, 125, 126, 129 and 169 of the *Framework Regulations*. These sections contain reference to requirements and associated guidance for interdependent systems.
- Based on the risk assessment, additional equipment and devices may be required to allow persons to escape from the immediate effects of a hazardous event to the temporary safe refuge. This should include smoke hoods, escape packs, self-contained breathing apparatus (SCBAs), flashlights, gloves, emergency descent control devices, etc.

Section 117 – Temporary Safe Refuge

117 (1) The operator must ensure that the installation is equipped with a temporary safe refuge that will, in the case of an emergency, including an accidental event,
(a) provide sufficient space to accommodate all persons who may need to use the refuge until they have been evacuated, the accidental event has been brought under control or the emergency otherwise ends;
(b) protect the persons referred to in paragraph (a) from fire, gas release and explosion hazards for as long as they are in the refuge;
(c) provide the means for communication and command and, if applicable, for the monitoring and control of the accidental event for as long as persons are in the refuge; and
(d) provide signage and lighting to enable safe evacuation from the refuge.

Areas required to remain safe

(2) The operator must ensure that the accommodations area, main control centre and any other area of an installation that is required to remain safe for persons to occupy during an emergency, including the temporary safe refuge, are
(a) designed to prevent ingress of hazardous substances; and
(b) designed and located to enable occupation for the time required to implement emergency and evacuation procedures.

Periodic verification

(3) The operator must verify on a periodic basis that the temporary safe refuge meets the requirements set out in subsections (1) and (2) and must record the findings resulting from the verification.

General

- Refer to the requirements and associated guidance for emergency response equipment and other requirements for this area under Parts 5, 8 and 12 of the *OHS Regulations*.
- Refer to the requirements and associated guidance for physical and environmental conditions, design for intended use and location, risk assessments, passive fire and blast protection, hazardous and non-hazardous areas, ventilation systems, ignition prevention, escape routes, life-saving appliances, electrical systems, control and monitoring systems, emergency electrical power and communication systems under sections 98, 104, 105, 106, 107, 108, 112, 113, 114, 115, 116, 118, 119, 122, 123, 124, 125, 126, 129 and 169 of the *Framework Regulations*. These sections contain reference to requirements and associated guidance for interdependent systems.
- Typically, temporary safe refuges are designed to provide protection for:
  - at least two hours on a production installation; or

    - at least one hour on a drilling installation.

  If they are not demonstrated or maintained to meet the criteria, evacuation plans should be adjusted to reflect the actual protection time that is provided.
- With respect to 117(3) of the *Framework Regulations*, temporary safe refuges should be fully inspected and tested at least once every three years.
- An impairment that causes the control rooms, muster areas or temporary safe refuges to be unable to meet its performance requirements should result in shutdown of production and drilling operations.

Standards

Additional guidance is provided in the following:

- *ISO 17776 Petroleum and natural gas industries - Offshore production installations - Major accident hazard management during the design of new installations* provides guidance for the conduct of temporary refuge integrity analysis.
- *ISO 15544 Oil and gas industries - Offshore production installations -- Requirements and guidelines for emergency response.*
- *ISO 13702 Petroleum and natural gas industries - Control and mitigation of fires and explosions on offshore production installations - Requirements and guidelines*.
- *ISO 35102 Petroleum and natural gas industries – Arctic operations – Escape, evacuation and rescue from offshore installations.*
- *NORSOK Z-013 Risk and emergency preparedness assessment* and *NORSOK S-001 Technical Safety.*
- *NOPSEMA Guidance Note GN 1051 Supporting Safety Studies.*
- Guidance on certain aspects are also found in the following references:
    - Guidance on temporary refuges is provided in *ISO 15138 Petroleum and natural gas industries – Offshore Production Installations - Heating, ventilation and air-conditioning.*
    - Guidance on temporary refuge integrity is provided in the *Health and Safety Executive Offshore Information Sheet 1/2006 – Testing regime for offshore TR-HVAC fire dampers and TR pressurization requirements* and *Health and Safety Executive HID Inspection Guide Offshore – Inspection of Temporary Refuge Integrity.*
    - Guidance on testing the integrity of temporary refuges is provided in the *Energy Institute Guidance on Integrity Testing for Offshore Installation Temporary Refuges*.
- Refer to requirements and associated guidance for operations and maintenance of these systems under sections 153, 156, 157 and 158 of the *Framework Regulations*.

Section 118 – Exits, Access and Escape Routes

118 (1) An operator must ensure that
(a) in any area where persons are normally present on an installation, there are at least two exits, each connected to an escape route that provides safe, direct and unobstructed access to temporary safe refuges, muster areas, embarkation stations and evacuation points; and
(b) there are means for persons to descend to the water.

Exception

(2) Despite paragraph (1)(a), if an area referred to in that paragraph has an area less than 20 m^2 or is a passage less than 5 m in length, the operator must ensure that there is at least one exit as described in that paragraph in that area.

Distancing — exits

(3) The operator must ensure that the exits referred to in paragraph (1)(a) are separated as far apart from each other as possible to increase the likelihood that at least one exit and its connected escape route will be passable during an accidental event.

Location of escape routes

(4) The operator must ensure that the installation has escape routes on two of its sides.

Safe evacuation

(5) The operator must ensure that all escape routes from an accommodations area or a temporary safe refuge to a muster area, embarkation station or evacuation point are clearly marked and illuminated and provided with fire protection to allow for the safe evacuation of persons in a time frame determined in the safety studies referred to in section 116.

Size of escape routes

(6) The operator must ensure that each escape route is of sufficient size to enable the efficient movement of the maximum number of persons who may need to use it, as well as unrestricted manoeuvring of firefighting equipment and stretchers, taking into account the maximum number of persons who can be accommodated on the installation.

General

- Refer to the requirements and associated guidance for emergency response equipment and escape under Parts 5, 6, 8, 11, 12 and 17 of the *OHS Regulations*.

- Refer to the requirements and associated guidance for physical and environmental conditions, design for intended use and location, risk assessments, passive fire and blast protection, hazardous and non-hazardous areas, ventilation systems, ignition prevention, temporary safe refuge, life-saving appliances, electrical systems, control and monitoring systems, emergency electrical power and communication systems under sections 98, 104, 105, 106, 107, 108, 112, 113, 114, 115, 116, 117, 119, 122, 123, 124, 125, 126, 129 and 169 of the *Framework Regulations*. These sections contain reference to requirements and associated guidance for interdependent systems.
- Based on the risk assessment, additional equipment and devices may be required to allow persons to escape from the immediate effects of a hazardous event to the temporary safe refuge. This should include smoke hoods, escape packs, self-contained breathing apparatus (SCBAs), flashlights, gloves, emergency descent control devices, etc.
- With respect to paragraph 118(1)(b) of the *Framework Regulations*, means for persons to descend to the water should consider the placement of immersion suits, lifejackets, emergency descent devices, embarkation ladders, stairs, life rafts or a combination thereof. The type of equipment, number and size of each and distribution should consider the number and sizes of persons onboard and their distribution.
- To the extent practicable, escape routes between two levels should be provided by stairways.
- Loose equipment should not be stored in or adjacent to escape routes on a floating installation. Unsecured equipment may shift and inadvertently block routes or doors.
- A means should be provided to keep escape routes, evacuation stations, embarkation points and access to emergency equipment free of ice during winter months.
- The placement of additional equipment, changes in equipment, changes in process or the addition of persons, whether it be permanent or temporary, may have an impact on the associated risk assessments that have been undertaken. Changes should be assessed through a formal management of change process to determine if the existing measures implemented within this section will continue to be appropriate following a change.

Muster Areas and Evacuation Stations

Considerations for muster areas and evacuation stations are as follows:

- An effective and efficient means to track and account for all persons onboard should be provided (e.g., muster boards, T-Card system).
- Good acoustics should be provided to allow persons conducting works or activities to hear the public address system and instructions.
- Sufficient space should be provided to don immersion suits.

Standards

Additional guidance is provided in the following:

- SOLAS, MODU Code and associated IMO resolutions and circulars contain guidance on muster and embarkation stations, embarkation ladders and escape/evacuation routes.
- Flag state and classification society rules.

- *ISO 17776 Petroleum and natural gas industries - Offshore production installations - Major accident hazard management during the design of new installations.*
- *ISO 15544 Oil and gas industries - Offshore production installations -- Requirements and guidelines for emergency response.*
- *ISO 13702 Petroleum and natural gas industries - Control and mitigation of fires and explosions on offshore production installations - Requirements and guidelines*.
- *ISO 35102 Petroleum and natural gas industries – Arctic operations – Escape, evacuation and rescue from offshore installations.*
- *NORSOK Z-013 Risk and emergency preparedness assessment* and *NORSOK S-001 Technical Safety.*
- *NOPSEMA Guidance Note GN 1051 Supporting Safety Studies.*
- *NFPA 101 Life Safety Code* provides guidance on means of egress.

Operations and Maintenance

Refer to requirements and associated guidance for operations and maintenance of these systems under sections 153, 156, 157 and 158 of the *Framework Regulations*.

Section 119 – Life-Saving Appliances

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119 (1) An operator must ensure that an installation is equipped with life-saving appliances that
(a) are sufficient in number and have the necessary redundancy to ensure their availability in any emergency situation; and
(b) meet the requirements of the LSA Code and the annex to International Maritime Organization Resolution MSC.81(70), Revised Recommendation on Testing of Life-Saving Appliances, as if the installation were a vessel to which the Code and the Resolution apply.

Loads

(2) The operator must ensure that life-saving appliances can withstand all loads to which they may be subjected when they are in use.

Space requirements and weight

(3) The operator must ensure that, in determining the number of persons any lifeboat, life raft or marine evacuation system can accommodate, the persons' space requirements and weight while wearing immersion suits are taken into account.

Arrangement and selection

(4) The operator must ensure that the arrangement and selection of life-saving appliances are based on
(a) the safety studies referred to in section 116, in particular any escape and evacuation analysis that takes into account any major accidental events; and
(b) the results of the risk assessment conducted under subsection 107(1).

Position

(5) The operator must ensure that copies of a plan showing the position of all life-saving appliances are posted at the installation, including in the main control centre and in any accommodations area and work area.

Lifeboats - availability

(6) For the purposes of subsections (1) and (2), the operator must ensure, with respect to the lifeboats on an installation, that
(a) they are kept in at least two separate locations, one of which is adjacent to a temporary safe refuge;
(b) they have a combined capacity to accommodate the total number of persons on board the installation – and those kept in each location have a combined capacity to accommodate the total number of persons assigned to that location – even in the event that any one lifeboat is lost or rendered unusable; and
(c) if the installation is a floating platform, those lifeboats that are able to be launched under any credible scenario of angle of heel have a combined capacity to accommodate the total number of persons on board the installation.

Lifeboats - specifications

(7) The operator must ensure that the lifeboats are totally enclosed and are fire-protected.

Lifeboats - continuous communication

(8) The operator must ensure that each lifeboat is capable of being in continuous communication with each other lifeboat and with other vessels in the area.

Lifeboats - towing devices

(9) The operator must ensure that each lifeboat is equipped with towing devices.

Life rafts

(10) For the purpose of subsections (1) and (2), the operator must ensure that the life rafts on an installation have a combined capacity to accommodate the total number of persons on board the installation.

Continuous verification

(11) The operator must verify on a continuous basis that the lifeboats, life rafts and other life-saving appliances are available and in a condition to perform as intended and must record the findings resulting from each verification.

a. General

- Refer to the requirements and associated guidance for means of evacuation, falls into the ocean, launching drills and hyperbaric evacuation (if required) under sections 21, 29 and 30 and Part 32 of the *OHS Regulations*.
- Refer to the requirements and associated guidance for physical and environmental conditions, design for intended use and location, risk assessments, passive fire and blast protection, ignition prevention, evacuation and escape, transportation and positioning, electrical systems, control and monitoring systems, emergency electrical power, communication systems, fire protection systems, pressure systems, mechanical systems, materials handling equipment and asset integrity under sections 98, 104, 105, 106, 107, 108, 110, 112, 115, 116, 118, 121, 122, 123, 124, 125, 126, 129, 134, 135, 136, 137 and 169 of the *Framework Regulations.*
- Operators should demonstrate that installations are fitted with the best evacuation technology available and as such, should be equipped with an enhanced evacuation system to provide a means for personnel to safely escape any foreseeable hazards.[28] As an example, the enhanced evacuation system (e.g., PrOD device or equivalent) for lifeboats should ensure that the lifeboats are oriented in a direction that directs them away from hazards associated with collision with the installation, hydrocarbon or toxic gases, smoke and fires on the sea. The orientation should also consider any prevailing physical and environmental conditions.
- In choosing the means of evacuation, the operator should recognize explicitly how physical and environmental conditions affect or limit the performance capabilities of evacuation and means of rescue and recovery. The performance of evacuation, rescue and recovery systems normally degrades as physical and environmental conditions deteriorate. A design physical and environment condition limitation for life-saving appliances is the mildest condition in which the equipment is unseaworthy or incapable of being safely launched. Conditions that cause capsizing or result in excessive motions for persons also constitute such a limit, as does the inability to safely clear the hazards. The operating (e.g., trim, heel) and physical and environmental condition limitations (e.g., wind, temperature, sea state, pack ice) with respect to the use of each type of evacuation, rescue and recovery system should be well known to offshore persons and actions should be taken as the physical and environmental conditions deteriorate to reduce the risk of evacuation. This should include limiting some types of work, initiating a planned shutdown or considering down-staffing based on weather forecasts.

[28] Refer to recommendations from the *Ocean Ranger Inquiry*.

- Another consideration in choosing the means of evacuation during ice season is the ability to safely launch and move away from the installation in pack ice.
- The type of life-saving appliance, the number and size of the units of each, and their distribution around the installation should consider the number and sizes of POB and their locations during operations and the likelihood that equipment will be impaired by initiating hazards.
- Refer to requirements and the associated guidance provided for subsection 118(5) of the *Framework Regulations* for fire protection for escape routes and embarkation stations. In addition, if there is a risk of damage from an explosion, the embarkation station itself should either be located away from or protected from any impacts from explosions.
- During operations in winter months, all life-saving appliances should be suitable for use in the expected temperatures.
- The placement of additional equipment, changes in equipment, changes in process or the addition of persons, whether it be permanent or temporary, may have an impact on the associated risk assessments that have been undertaken. Changes should be assessed through a formal management of change process to determine if the measures implemented will continue to be appropriate following a change. Additional persons onboard may also result in the addition of life-saving appliances.

b. Standards

Additional guidance is provided in the following:

- SOLAS, the MODU Code and associated IMO resolutions or circulars, however, the following should be noted:
  - Design, testing and commissioning requirements specify a minimum air temperature of -15°C (e.g. cold engine starting test). According to the requirements and associated guidance under sections 104 and 106 of the *Framework Regulations,* equipment should be designed and demonstrated to be suitable for the physical and environmental conditions it is expected to operate in. As such, lifeboats should be confirmed suitable for operation in the conditions expected.
  - Construction requirements within the LSA Code specify that lifeboats must be capable of being safely launched under all conditions of trim of up to 10° and list of up to 20°. As such, the actual design of the lifeboats should be confirmed to be suitable against the operational limitations of the installation and if not suitable, other measures should be implemented.
  - Most life-saving appliances are designed to the LSA Code using an average per passenger weight of 75 kg or 82.5 kg. With respect to subsection 119(3) of the *Framework Regulations*, the lifting capacity, seaworthiness and space provided in life-saving appliances (e.g., lifeboats, life rafts) should be evaluated and the associated lifting capacity of launching appliances based on an average individual weight of 100 kg (including the immersion suit) or on the actual average individual weight of a person plus the weight of an average immersion suit. The equipment should be used accordingly and associated evacuation procedures and life-saving plans should be updated based on the

results. Operators should also assess whether the seating arrangements and seatbelts are suitable for all range of sizes of persons (e.g., small, large, tall) who may be onboard the installation. Additional guidance on conducting these assessments are in the *Health and Safety Executive Offshore Information Sheet 12/2008 Big persons in lifeboats.*

- Flag state and classification society rules.
- *Transport Canada's TP 14475 Canadian Life-Saving Appliance Standard* and Transport Canada's *Lifesaving Equipment Regulations* should also be consulted, as it contains additional considerations for operating in the *Offshore Area*.
- *ISO 17776 Petroleum and natural gas industries - Offshore production installations - Major accident hazard management during the design of new installations* provides guidance on escape, evacuation and rescue (EER) analysis.
- *ISO 15544 Oil and gas industries - Offshore production installations -- Requirements and guidelines for emergency response*; however, additional consideration should be given to precautionary evacuation before exceeding the design limits of an installation.
- *ISO 35102 Petroleum and natural gas industries – Arctic operations – Escape, evacuation and rescue from offshore installations* provides details with respect to meeting the requirements of sections 104 and 106 of the *Framework Regulations*, including operations in colder temperatures, icing and pack ice. However, there are some exceptions with respect to implementation of this document:
    - Direct evacuation methods to a standby vessel using bridges, motion-compensated gangways or chutes and lowering of evacuation craft directly onto the deck of a standby vessel have not been successfully demonstrated in the *Offshore Area* as a viable evacuation option as the sea states are typically > 2 m. Direct transfer to a standby vessel via personnel transfer device can be used as an option but also has limited sea state restrictions (typically 3 – 3.5 m sea states).
    - The use of a standby ice management vessel is discussed to keep an installation clear of pack ice. In this circumstance, consideration should be given to whether the vessel is safe to operate in a hazardous gas environment and the measures that should be implemented if it is not designed to operate in that environment (e.g., Contingency Plans should specify the safe and controlled shutdown of drilling or production installations before physical and environmental conditions (including pack ice) reach the point that may prohibit a safe evacuation).
- *NORSOK S-001 Technical Safety.*
- *IOGP Report 434-19 Risk Assessment Data Directory Report— Evacuation, Escape and Rescue.*

c. Lifeboats

- With respect to subsection 119(7) of the *Framework Regulations*, refer to requirements for "fire-protected" in the LSA Code.
- With respect to subsection 119(8) of the *Framework Regulations*, the communication system should be a two-way fixed radio and it should also be capable of communication with other life rafts and fast rescue boats in the area. Refer to paragraphs 129(2)(a) and (b) of the *Framework Regulations* for requirements. Communication systems should be

easy to use and provided with operating instructions and list of emergency communication channels.

- With respect to subsection 119(9) of the *Framework Regulations*, the towing device should be suitable for connection to a support craft or other vessel and should be suitable for expected operating and physical and environmental conditions.

Lifeboats should be:

- In addition to being a TEMPSC according to the LSA Code, freefall lifeboats should follow or be assessed against *DNV-ST-E406 Design of Free Fall Lifeboats* using physical and environmental conditions of the area in which it is planned to be operated and taking into consideration the latest IMO Circulars.
- Equipped with two independent starting methods for the engine.
- If planned to be used in cold climate operations, equipped with a means of ensuring prompt engine start and launching devices should have suitable winterization to prevent ice from interfering with launching.
- Equipped with emergency power supply to the lifeboats and the disconnection should be automatic without sparks when launching or lowering.
- Equipped with a fixed search and rescue device or AIS with GPS and external antenna. Refer to paragraph 129(2)(a) of the *Framework Regulations* for requirements.
- Equipped with a gyro heading display or equivalent.
- Equipped with hooks and maintenance pendants rated for the full weight of the boat plus the full complement with a factor of safety in alignment with IMO.
- Designed to consider human factors as it relates to operability, maintenance, comfort and sizing.
- In the case of a column-stabilized mobile offshore platform and a fixed platform, installed to launch in a bow out aspect.
- In the case of a self-elevating mobile offshore platform, installed such that it can clear each leg, column, footing, brace or mat and any other similar structure below the hull.

For a drilling or production installation or an accommodations installation adjacent to a drilling or production installation, lifeboats should be:

- equipped with a self-contained air support system (refer to requirements for "self-contained air support systems" in the LSA Code); and
- designed such that friction or impact sparking of launching devices is prevented.

d. Life rafts

Life rafts should have a portable AIS or search and rescue device and portable VHF radios should either be provided at each embarkation station or brought by coxswains when mustering at the embarkation station.

e. Fast Rescue Boat

- Refer to the requirements and associated guidance under section 29 of the *OHS Regulations*.

- If the installation is equipped with a fast rescue boat, it should also meet the additional requirements for fast rescue boats under the *LSA Code* and other requirements of flag state.

f. Lifejackets and Immersion Suits

Refer to the requirements and associated guidance under Parts 5 and 8 of the *OHS Regulations*.

g. Life-saving Plans

Refer to the requirements and associated guidance under section 157 of the *Framework Regulations* and Part 5 of the *OHS Regulations*.

h. Operation and Maintenance of Life-saving Appliances

Additional guidance for operations, inspection, testing and maintenance of life-saving appliances is as follows:

- Refer to requirements and associated guidance for operations and maintenance of these systems under sections 153, 156, 157 and 158 of the *Framework Regulations*.
- Refer to the above referenced IMO and ISO references, classification society rules and the latest IMO circulars (e.g., MSC.1/Circ.1206/Rev.1) and resolutions for guidance respecting the ongoing operations, inspection, testing and maintenance of life-saving appliances.
- Additional consideration should be given to implementing additional or alternative inspection, testing and maintenance measures given that IMO and manufacturer requirements may not take into consideration long term operation and exposure to the physical and environmental conditions experienced in our *Offshore Area*.
- Detailed operations and maintenance manuals should be provided and instructions for launching and release should be posted both inside the lifeboat and at the davit winch.
- Operations and maintenance manuals and instructions should consider manufacturer recommendations and other requirements of subsection 87(1) of the *OHS Regulations* and section 159 of the *Framework Regulations*.
- With respect to lifeboats:
  - They should be lowered and launched at the draft(s) (e.g., transit, operating, survival) at which the installation may be operated before going to location and periodically (in mild physical and environmental conditions) to:
    - demonstrate the lifeboat and any enhanced evacuation system (e.g., PrOD) functions as intended;
    - demonstrate it meets the performance criteria of IMO, flag state and the classification society, as applicable;
    - demonstrate it meets the performance criteria of associated safety studies;
    - test the air quality inside the lifeboat after a sufficient run time;
    - provide coxswains with hands-on training, familiarity and comfort in the use of the lifeboat and its associated equipment; and
    - record lowering speed and other details such as, hydraulic pressure of the PrOD system and weight of the lifeboat (to account for any water absorption over time), so

that they can be compared to data collected during subsequent tests. If any issues are noted, they should be assessed and plans made to rectify.

- The planned maintenance system for lifeboats should provide an ongoing demonstration of the preparedness of the equipment through periodic inspection or testing and should be based on a thorough FMEA based on the operating and physical and environmental conditions in which they will be operated. In addition to weekly inspections, monthly inspections, annual testing and five-yearly tests specified in SOLAS, this should include the following:
  - Lowering of the lifeboat to a sufficient height above the water to confirm the condition of the hull, hook release and retrieval systems and davit system. This should be conducted in mild environmental conditions.
  - Testing of the water spray protection system, if installed, when the lifeboat is stowed onboard the installation and associated instructions.
  - Running of the engines for a sufficient amount of time (e.g., 15 - 30 minutes) to test the performance of the engine and to test the air quality inside the lifeboat, subject to any manufacturer's instructions (e.g., provision of cooling water). This should include testing for all exhaust gases (e.g., CO) and for oxygen deficiency. The three-minute run time specified in SOLAS may not provide enough time for hazardous atmospheres to be detected.
  - Testing of hydrostatic release mechanisms on a prescribed frequency (e.g. every six months).
  - Testing or inspection of stuffing boxes.
  - Testing of batteries and communication systems.
  - Inspection, testing and air quality checks of the self-contained air breathing system.

Section 120 – Installation Designed for Removal

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120 (1) An operator must ensure that an installation is designed to facilitate its removal from the offshore area at the end of its design service life and to reduce any risks to safety, adverse effects on the marine environment and interference with navigation and other uses of the sea that may occur during and after its removal.

Exception

(2) Subsection (1) does not apply if the Board has approved, in the development plan, the abandonment or an alternative use of the installation.

- Refer to the definition of "accommodations installation", "drilling installation", "production installation" and ancillary definitions (e.g., drilling unit, drilling rig, marine activities) in section 1 of the *Framework Regulations*.

- Refer to the requirements and associated guidance on physical and environmental conditions and design for intended use and location in sections 104, 105 and 106 of the *Framework Regulations*.
- Refer to any conditions or commitments from associated Environmental Assessments and Impact Assessments.
- Refer to any conditions or commitments from associated *Development Plans*.
- Modifications to an installation should consider the effect on its ability to be removed at end of life.
- If local data is not available, allowance should be made to assess seabed stability, scour and other phenomena that would affect the acceptability of criteria for removal of materials installed below the seabed e.g., cutting of piles at a nominal depth of 3 m below seabed.
- Requirements and guidance from other authorities should be considered, including:
  - UNCLOS Part 5, Article 60.
  - *IMO Resolution A.672(16) Guidelines and standards for the removal of offshore installations and structures on the continental shelf and in the exclusive economic zone*.
  - Associated laws on removal and disposal of installations and associated systems and equipment, along with handling and disposal of waste material.

Section 121 - Transportation and Positioning

121 (1) An operator must ensure that an installation, or any part of it, is transported and positioned
(a) in a manner that does not compromise safety or the protection of the environment;
(b) in a manner that minimizes interference with and hazards to other activities in proximity to that installation;
(c) under the supervision of a competent third party;
(d) in the case of a self-elevating mobile offshore platform, with the legs of the platform secured in accordance with the rules of the classification society that issued the certificate of class required under section 140; and
(e) with the support of vessels that are classified in accordance with section 177.

Risk Assessment

(2) Before an installation, or any part of it, is transported and positioned, the operator must ensure that the following requirements are met:
(a) a risk assessment must be conducted that takes into account
> ***(i) personnel requirements,***
> ***(ii) the towing vessels that will be used, the towing plan, including towing arrangements, and the operating limits of the towing equipment's components,***
> ***(iii) the processes and control measures to be implemented to ensure safety and the protection of the environment,***

(iv) physical and environmental conditions and the ability to reliably forecast those conditions, and

(v) any contingency measures to be taken in the event of adverse physical and environmental conditions or the occurrence of any other foreseeable adverse event during transportation and positioning; and

(b) a transportation and positioning plan must be prepared that takes into account any requirements of the competent third party referred to in paragraph (1)(c) and, if the installation is a floating platform, the plan must be prepared in accordance with the rules of the classification society that issued the certificate of class required under section 140.

- This requirement is interpreted to apply to:
  - towing and positioning of a new installation;
  - movement of an installation either from shore base or other jurisdiction onto location;
  - moves between wells with a self-elevating platform (i.e., does not include moves between wells with a MODU that is classed as self-propelled);
  - removal of an installation; or
  - installation or removal of a component of an installation (e.g., vessel performing construction activity).
- This requirement is interpreted to not apply to floating production installations that are designed to move on and off location, are self-propelled, and are under the command of a master mariner for this operation.
- Refer to the requirements and associated guidance on physical and environmental conditions and design for intended use and location in sections 104, 105 and 106 of the *Framework Regulations*.
- Refer to the requirements and associated guidance for any support vessel that may be used in paragraph 41(g) of the *Framework Regulations*.
- Refer to any conditions or commitments from associated Environmental Assessments and Impact Assessments or authorizations and associated approvals.
- Refer to any conditions or commitments from associated *Development Plans*.
- Refer to requirements of flag state and the classification society and any requirements of CCG, DFO, etc.
- With respect to the role of the CA, refer to the requirements and associated guidance under Part 5 of the *Framework Regulations*.
- With respect to the role of Transport Canada Marine Safety, refer to the MOU on the *Regulator*'s websites.
- With respect to paragraph 121(1)(c) of the *Framework Regulations*, this is interpreted to include a marine warranty surveyor or the classification society. The level of supervision provided during the transportation and positioning of an installation, or any part of it, is at the discretion of the competent third party.
- With respect to subsection 121(2) of the *Framework Regulations*, the following measures should be considered:

  - Provide redundancy for critical equipment being used for the tow and set down of the installation.
  - Limit the number of POB to those that are necessary for the execution of the activity.
  - Limit the amount of hazardous substances onboard to a level necessary for safety and activity during transit.
  - Limit the amount of temporary equipment and cargo onboard to as low as practicable.
  - Sea fastening of all equipment and cargo before transit, including securing and locking out any system that should not be used during transit (e.g., elevators, cranes).
  - Ensure that fire suppression systems are available at the transit height or other measures are implemented.
  - Ensure sufficient life-saving appliances for the number of personnel onboard can be launched effectively at the transit height.
  - Ensure helicopter operations can be undertaken, if required.
  - Obtain accurate and independent weather forecasts for the duration of the planned activity. Additional time should be factored in to account for other operational or technical issues that may arise.
  - Monitor weather forecasts, physical and environmental conditions and installation motions closely.
  - Identify contingency set down locations along the planned route for a fixed or self-elevating platform.
- Additional guidance is provided in the following:
  - With respect to fixed or floating installations and components of an installation such as topsides modules, subsea templates, moorings or foundations refer to *ISO 19901-6 Petroleum and natural gas industries - Specific requirements for offshore structures - Part 6: Marine operations*.
  - With respect to moves conducted by MODUs, refer to *DNV-ST-N001 Marine operations and marine warranty, DNV-ST-N002 Site specific assessment of mobile offshore units for marine warranty* and *UKOOA Guidelines for Safe Movement of Self-Elevating Offshore Installation (Jack-Ups).*

Section 122 - Electrical System

122 (1) An operator must ensure that any electrical system on an installation is designed to avoid any abnormal conditions and faults that may endanger the installation or, if it is not possible to avoid them, to provide alerts of those conditions and faults and mitigate their effects.
Safety and reliability

(2) The operator must ensure that all electric motors, lighting fixtures, electrical wiring and other electrical equipment on an installation are safe and reliable under all foreseeable operating conditions.

Device for monitoring insulation level to earth

(3) If a primary or secondary distribution system for electrical power, heating or lighting with no connection to earth is used on an installation, the operator must ensure that the system is equipped with a device that continuously monitors the insulation level to earth and produces an audible or visual alarm to indicate abnormally low insulation values.

Main electrical power supply

(4) The operator must ensure that the main electrical power supply on, or to, an installation
(a) ensures continuous availability of power generation and distribution;
(b) includes at least two power plants or other supply sources, not including emergency power plants;
(c) is capable of supporting all normal operations without recourse to the emergency electrical power supply required under subsection 126(1); and
(d) is capable of supporting all operations, other than drilling and production, if one of the power plants is out of operation.

Primary circuit shutdown

(5) The operator must ensure that the primary circuits from a power plant serving an installation are capable of being shut down from at least two separate locations, one of which must be the site of the power plant.

General

- Refer to requirements and associated guidance for equipment, in general and electrical systems under Parts 18 and 27 of the *OHS Regulations*. Part 27 of the *OHS Regulations* also contains guidance with respect to certification of hazardous area rated equipment by an independent certification body (e.g., IECEx) and guidance with respect to cold impact and cold bend tests for cabling.
- Refer to the requirements and associated guidance for physical and environmental conditions, risk assessments, hazardous and non-hazardous areas, ignition prevention, control and monitoring systems and emergency electrical power under sections 98, 104, 105, 106, 107, 108, 113, 115, 123, 124, 125, 126 and 169 of the *Framework Regulations*.

Design, Selection, Installation and Certification of Electrical Systems

In addition to the requirements and associated guidance provided in Part 27 of the *OHS Regulations*, guidance is provided in the following:

- *IEC 61892 Mobile and fixed offshore units – Electrical Installations* - series of standards (including Annex B - Cold Climate precautions).

- *IEC 60079 Explosive Atmospheres* - series of standards.
- MODU Code for MODUs.
- Requirements for tankers in SOLAS and *IEC 60092 Electrical Installations in ships* – series of standards - for floating production platforms.
- Requirements of flag state.
- Associated IEC standards, standards referenced in API RP 14F/FZ or in the Canadian Electrical Code, for the type of application for which the electrical equipment is to be used and the factors to be considered (e.g., ingress protection, electromagnetic compatibility, high voltage switchgear, umbilicals). This should also include:
  - *API RP 14F Recommended Practice for Design, Installation, and Maintenance of Electrical Systems for Fixed and Floating Offshore Petroleum Facilities for Unclassified and Class 1, Division 1, and Division 2 Locations* and *API RP 14FZ Design and Installation of Electrical Systems for Fixed and Floating Offshore Petroleum Facilities for Unclassified and Class I, Zone 0, Zone 1, and Zone 2 Locations*, as applicable. It should be noted that API RP 14FZ has not been updated to mirror all elements in the latest version of API RP 14F and therefore, appropriate measures should be considered to address these additional elements, if applying API RP 14FZ.
- In addition:
  - All temporary or third party electrical equipment should be constructed to a standard that is equivalent to requirements or standards such as IEC, API RP 14F/FZ, or CSA.
  - For equipment required to stay live in the event of an emergency shutdown, refer to requirements and associated guidance under section 115 of the *Framework Regulations.*
  - Measures should be put in place to ensure compliance to any conditions on the Certificate of Conformity or equivalent that is provided with the electrical equipment.
  - A register should be maintained of all hazardous area rated equipment whether it is installed in a hazardous or a non-hazardous area.
  - The selection or design of electrical equipment that is subject to movement, either because it is installed on equipment that moves or is onboard an installation subject to flexing, should consider the intended range of motion, acceleration and velocity of movement, as applicable.
  - Lights, including lights installed in accordance with subsection 127(1) of the *Framework Regulations* should be designed, installed and controlled - including the timing, direction, intensity and glare of light fixtures - to avoid excessive light pollution and attraction of migratory birds, while meeting operational, health and safety requirements.

Operations and Maintenance of Electrical Systems

- Refer to requirements and associated guidance for operations and maintenance of these systems under sections 153, 156, 157 and 158 of the *Framework Regulations*.
- In addition to the requirements and associated guidance provided in Part 27 of the *OHS Regulations*, additional guidance for the operation and maintenance of electrical systems on drilling, production and accommodations installations is provided in the following:
  - Annex A and Annex F of *API RP 14F/14FZ*
  - *IEC 60079-17 Explosive Atmospheres Electrical Installations Inspection and Maintenance*

  - *IEC 60079-19, Explosive atmospheres - Part 19: Equipment repair, overhaul and reclamation*
- The preventative maintenance program should ensure the rating and integrity of hazardous area rated equipment installed in non-hazardous areas, as this equipment may provide a source of ignition if it remains live following an emergency shutdown.
- In addition to any prescribed requirements and associated guidance for training and competency under Part 27 of the *OHS Regulations,* additional guidance for competency is provided in IEC 60079-17 for personnel involved in the operation and maintenance of electrical systems.

Sections 123 - 125 - Control Systems and Software

123 (1) An operator must ensure that a control system is designed in accordance with the measures referred to in clauses 9(2)(b)(v)(D) and 10(2)(b)(v)(D) that are described in the operator's safety plan and environmental protection plan, respectively.

Requirements

(2) The operator must ensure that the control system is designed to meet the following requirements, taking into account human factors:
(a) controlled equipment must not be capable of being inadvertently activated;
(b) controlled equipment must not create a safety or environmental hazard in the event of system failure or shutdown;
(c) the system must have basic diagnostic capability; and
(d) the system must be capable of being operated simultaneously from multiple control stations without compromising safety.

Protection of hardware

(3) The operator must ensure that control system hardware is protected from circumstances, including excessive vibration, high electromagnetic field levels, electrical power disturbances and extreme temperatures or humidity levels or other physical and environmental conditions, that could cause mechanical damage to or degradation of the hardware or that could adversely affect the performance of the system.

Wireless remote control system

(4) The operator must ensure that any wireless remote control system includes
(a) a means for error checking to prevent the controlled equipment from responding to corrupt data; and
(b) a means for identification coding to prevent a transmitter other than the designated transmitter from operating the equipment.

Alternative means of control

(5) The operator must ensure that all control system functions that are required to ensure safety and are dependent on wireless communication links have an alternative means of control that can be activated without delay and without modification to the control system.

Inspection and testing

(6) Equipment that is to be operated by a new, repaired or modified control system must not be put into operation until the operator ensures that the control system has been inspected and tested to confirm that it functions as intended.

Documentation

(7) The operator must ensure that documentation containing an up-to-date description of the design, installation, operation and maintenance of the control systems is readily accessible for consultation and examination.

Integrated software-dependent control system

124 (1) An operator must ensure that an integrated software-dependent control system whose failure or malfunction would cause a hazard to safety or the environment is maintained to ensure its reliability, availability and security.

Control measures

(2) The operator must ensure that control measures are implemented to protect the integrated software-dependent system from any threat, including unauthorized access.

Safety-critical software

125 (1) The operator must ensure that any software that is a safety-critical element is
(a) secure, reliable and capable of being updated;
(b) designed, commissioned and updated by competent persons; and
(c) demonstrated to be fit for the purposes for which it is to be used through a testing and validation process that takes into account

> ***(i) all foreseeable operating conditions and emergency situations, and***
> ***(ii) system complexity, dependencies and interactions between systems, software failure modes and the level of risk associated with system failure or malfunction.***

Modification to features

(2) The operator must ensure that no modification to the features of the software is implemented unless
(a) the modified software has undergone the testing and validation process referred to in paragraph (1)(c); and
(b) the necessary internal approvals for the modification have been obtained, including the approval of the installation manager.

General

- Refer to the requirements for monitoring systems under section 169 of the *Framework Regulations*. The guidance for section 169 has been captured in this section of the Guideline.
- Refer to the requirements and associated guidance for any control, monitoring or automated functions, risk assessments or design, operation and maintenance under Part 10 of the *Framework Regulations*. If any control, monitoring or automated functions are identified under the *OHS Regulations* these should also be integrated into the installation's system (e.g., medical rooms, activation of emergency eyewash stations and showers, potable water systems, elevator alarms, general alarms, loss of diving bell).
- If a system or part of a system is required to be controlled or monitored by a code or standard that has been adopted, then the requirements of that code or standard should also be integrated into the installation's control and monitoring system.
- Refer to the requirements and associated guidance for human factors analysis and ergonomic considerations under section 41 of the *OHS Regulations*.
- With respect to subsection 123(6) of the *Framework Regulations*, the level of testing should be commensurate with the risk. In some cases, the control system can be tested in the field, but complex or high criticality functions should consider function testing on a simulator prior to operation.
- It is also interpreted that sections 123, 124 and 125 of the *Framework Regulations* apply to any control or monitoring system located onshore that interfaces with the offshore systems. The application of codes and standard to any onshore control room should be appropriate and should consider the level of control/monitoring for that onshore equipment. It should also consider the relevant regulations onshore and how those requirements may conflict with offshore requirements.

Design Considerations

- The motion associated with a floating platform may affect the effectiveness of safety instrumented systems that may be installed, and should be considered in the design.
- Changes to hardware or software or the addition of permanent or temporary equipment may have an impact on the associated risk assessments that have been undertaken and compliance to these regulations. These changes should be assessed through a formal management of change process to determine if the measures implemented within this section will continue to be appropriate following a change. Changes to software should be fully verified and tested before being introduced.

Operational Considerations

- Refer to requirements and associated guidance for operations and maintenance of these systems under sections 153, 156, 157 and 158 of the *Framework Regulations*.
- Any limitations with respect to the impact of physical and environmental conditions on the control or monitoring systems should be documented and communicated to operations personnel. Actions should be taken to shut down operations in a controlled manner before any limits are exceeded.
- Alarm settings should be formally documented in operating procedures and should not be changed unless they have been assessed through the formal management of change process. Procedures should guide personnel on how to respond to alarms.
- The data from the use and operation of these systems should be collected, analyzed and used to optimize the performance of the system.
- Periodic training on the control, monitoring and inhibiting of these systems should be provided and include training in process upsets and emergencies, such that personnel know the actions to take in the event of an emergency or process upset. To ensure that personnel are equipped to respond, this training should be carried out on a simulator.

Testing Considerations

Testing of these systems should demonstrate that the assumed functionality, reliability and availability of the safety systems are being achieved and this information should be used to optimize the performance of the system.

Standards

Guidance for these systems can be found in the following:

- SOLAS and associated IMO resolutions or circulars.
- Flag state and classification society rules.
- *ISO 13702 Petroleum and natural gas industries - Control and mitigation of fires and explosions on offshore production installations - Requirements and guidelines* contains guidance on automatic functions, responses to fires and explosions, electronic/electrical systems, pneumatic and hydraulic supply systems, the human-machine interface and frequency of testing critical devices. While this standard is not directly applicable to drilling or accommodations installations, many of the principles can be applied to other types of installations.
- *ISO 17776 Petroleum and natural gas industries - Offshore production installations - Major accident hazard management during the design of new installations* contains guidance on these systems and inherently safer design.
- *IOGP Report 454 Human factors engineering in projects*
- *IEC 63303 Human Machine Interfaces for Process Automation Systems*

- *NORSOK S-001 Technical Safety* contains guidance on performance requirements, risk reduction principles and inherent safety design, process safety systems, human-machine interface for central control room systems and fire protection for safety-critical equipment for these systems. In addition, standards for the management of alarm systems are referenced.
- *IEC 61511 Functional Safety – Safety instrumented systems for the process industry sector* and *IEC 61508 – Functional Safety of electrical/electronic/programmable electronic safety-related systems* contains guidance on these systems and reference standards that should be considered for security of these systems.
- *IEC 62657 Industrial Communication Networks – Wireless Communication Networks* contains guidance on wireless systems.
- *IOGP Report 627 Selection of system and security architectures for remote control, engineering, maintenance and monitoring* contains guidance for remote control (e.g., onshore control rooms), remote engineering, remote maintenance and remote monitoring. Remote monitoring and maintenance should only be considered if there is sufficient redundancy in systems, security frameworks are in place that are robust and tested, and the roles and responsibilities are clear. Remote control should only be considered if the risk can be demonstrated to be ALARP. Contingency Plans should also be in place in the event communications are lost or there is a cyber-attack.
- *API Std 670 Machinery Protection Systems* contains guidance for remote operations and wireless operations.
- *API RP 691 Risk-Based Machinery Management* contains guidance for training and competency.
- With respect to a production installation, refer also to:
  - *ISO 10418 Petroleum and natural gas industries – Offshore production installations – Process Safety Systems*.
  - *API RP 14C Analysis, Design, Installation, and Testing of Safety Systems for Offshore Production Facilities* contains guidance in relation to logic solvers, safety system bypassing, testing procedures and reporting procedures. In particular, it suggests frequencies for the testing of safety devices and systems and states that this frequency can be adjusted based on field experience. The change in interval can be supported by historical testing records.
- With respect to a drilling installation and related systems, refer also to:
  - MODU Code
  - *NORSOK D-001 Drilling Facilities*
  - *NORSOK D-002 Well Intervention Equipment*
  - *NORSOK D-007 Well testing, clean-up and flowback systems*

Section 126 - Emergency Electrical Power Supply

126 (1) An operator must ensure that an installation has an emergency electrical power supply that is independent of the main electrical power supply such that the following systems and equipment continue to function in the event of a failure of the main electrical power supply:
(a) lights at
(i) all embarkation and debarkation stations and evacuation points,
(ii) all escape routes, temporary safe refuges, service corridors, accommodations area corridors, stairways, exits and personnel lift cars,
(iii) all control centres, control stations and areas from which the communication system referred to in section 129 is controlled,
(iv) spaces from which drilling or production equipment, including any equipment that is critical to that equipment's operation, is controlled,
(v) spaces where equipment related to the emergency shutdown system referred to in section 133 and to the power plants referred to in paragraph 122(4)(b) is located,
(vi) areas where emergency response equipment is stored, and
(vii) aircraft landing areas and the location of any obstacle to take-off and landing;
(b) hazard detection systems, including the central monitoring system referred to in section 169 and the fire and gas detection system referred to in section 132;
(c) emergency response and life-saving systems, including life-saving appliances that require electrical power;
(d) the communication system referred to in section 129;
(e) the emergency shutdown system referred to in section 133;
(f) the lights and sound-signalling appliances referred to in subsection 127;
(g) in the case of a floating platform, the pumps and powered watertight doors and hatches that are necessary to stabilize the installation, having regard to the failure modes and effects analysis referred to in subsection 144(5);
(h) in the case of a column-stabilized mobile offshore platform, the ballast systems referred to in section 144;
(i) the systems and equipment that are necessary to safely suspend at any time drilling or production that is in progress, including
(i) blowout prevention systems, including the blowout preventer referred to in subsection 68(5),
(ii) any disconnectable mooring system referred to in section 148,
(iii) any disconnect system referred to in section 150, and
(iv) pumping systems; and
(j) any other system or equipment that requires electrical power and that is referred to in the operator's safety plan referred to in section 9 or its contingency plan referred to in section 11.

Mechanically driven generator
(2) If the emergency electrical power supply is a mechanically driven generator, the operator must ensure that

(a) the installation is equipped with a transitional source of electrical power, unless the generator will automatically start and supply the necessary power in less than 45 seconds from the time the main electrical power supply fails;
(b) the installation is equipped with a self-contained battery system that is designed, on failure or shutdown of both the main electrical power supply and the emergency electrical power supply, to automatically supply sufficient power to operate
(i) for a period of at least one hour, the lights that are located in any emergency exit route, any escape route, any space where equipment incorporating an internal combustion engine, gas turbine, electric motor, generator, pump or compressor is found, any control centre and any emergency assembly room and at every launching station of life-saving appliances,
(ii) for a period of at least one hour, the communication system referred to in section 129 and the general alarm system referred to in section 130, and
(iii) for a period of at least four days, the lights and sound-signalling appliances referred to in section 127; and
(c) the mechanically driven generator has redundancy in its starting capabilities and a dedicated fuel source.

Design and maintenance

(3) The operator must ensure that the emergency electrical power supply together with any transitional source of electrical power and self-contained battery system with which the installation may be equipped are designed and maintained such that
(a) they are able to provide the systems and equipment referred to in subsection (1) with an emergency power supply of sufficient capacity, taking into account starting currents and the transitory nature of electrical loads, and sufficient duration to ensure that the systems and equipment can function as intended and to allow for effective management of the installation during an emergency, including
(i) to allow for the complete shutdown and evacuation of the installation,
(ii) to facilitate emergency response and the safe escape, refuge and evacuation of persons or to maintain the integrity of the installation,
(iii) to ensure sufficient power so that systems that must operate simultaneously can do so,
(iv) in the case of a floating platform, to maintain the flotation and stability of the platform, and
(v) to bring a well to a safe state and maintain it in that state;
(b) their capacity to provide power to essential systems is not compromised during their maintenance;
(c) they have sufficient redundancy to ensure their reliability and, as far as is practicable, to ensure their functional and physical independence from other essential systems or, if that is not practicable, they are arranged so as not to adversely affect or be adversely affected by the operation of those systems; and
(d) they are readily accessible.

Protection from damage

(4) The operator must ensure that the emergency electrical power supply, transitional source of electrical power and self-contained battery system referred to in subsection (3) are arranged — or are otherwise protected from mechanical damage and damage caused by fire, explosion and physical and environmental conditions to which they may be exposed — so that they remain capable of fulfilling their intended functions under all foreseeable operating conditions, including, in the case of a floating platform, under the static and dynamic angles of inclination referred to in subsection 136(7).

Alert

(5) The operator must ensure that, in the event of a failure of the main electrical power supply, all control centres are alerted by means of an audible and visual signal that the installation is being powered by the emergency electrical power supply.

- Refer to requirements and associated guidance for risk assessments, electrical systems and mechanical systems and asset integrity under sections 98, 108, 110, 122 and 136 of the *Framework Regulations*.
- Refer to requirements and associated guidance for lighting and electrical systems on all marine installations or structures under section 24 and Parts 15 and 28 of the *OHS Regulations*. In relation to “personnel lift cars”, refer also to requirements for elevators and personnel lifts under Part 19 of the *OHS Regulations*.
- Additional guidance on emergency electrical power is provided under section 10 and Annex C.1 of *ISO 13702 Petroleum and natural gas industries - Control and mitigation of fires and explosions on offshore production installations - Requirements and guidelines*. With respect to paragraph 126(1)(j) of the *Framework Regulations*, other systems or equipment that should be considered to be provided with emergency power include:
  - lighting for vents and wind direction indicator illumination for helicopter operations;
  - medical rooms;
  - instrument air compression systems;
  - diesel transfer pumps;
  - ventilation and cooling systems for safety-critical elements;
  - lighting of machinery spaces to allow restoration of service;
  - radars;
  - all permanently installed battery chargers servicing emergency equipment; and
  - any other equipment necessary to maintain the stability of the installation.
- Refer to requirements and associated guidance for operations and maintenance of these systems under sections 153, 156, 157 and 158 of the *Framework Regulations*.

Section 127 - Lights and Sound-Signalling Appliances

127 An operator must ensure that an installation is equipped with the lights and sound-signalling appliances that are required by the Collision Regulations as if that installation were a Canadian vessel to which those Regulations apply, unless compliance with the height and distance requirements of those Regulations is not possible, in which case the lights and appliances must be installed to maximize their audible and visual alerting capabilities for collision avoidance.

- Refer to the requirements and associated guidance for physical and environmental conditions and electrical systems under sections 104 and 122 of the *Framework Regulations*.
- Refer to any applicable requirements of Transport Canada Marine Safety for navigation and collision aids (e.g., *Navigation Safety Regulations*).
- Refer to the requirements and associated guidance for aircraft landing areas under sections 174 – 176 of the *Framework Regulations*.
- Refer to flag state and classification society rules, as applicable.
- Refer to requirements and associated guidance for operations and maintenance of these systems under sections 153, 156, 157 and 158 of the *Framework Regulations*.

Section 128 - Radar

128 An operator must ensure that an installation other than an unattended installation is equipped with radar for identifying hazards in proximity to the installation and that the radar is continuously monitored.

General

- Refer to the requirements and associated guidance under section 173 of the *Framework Regulations* with respect to safety zone entry and boundaries for collision avoidance.
- Refer to the requirements and associated guidance for physical and environmental conditions and electrical systems under sections 104 and 122 of the *Framework Regulations*.
- Refer to applicable requirements of Transport Canada for navigation and collision aids (e.g., *Navigation Safety Regulations*).
- Refer to flag state and classification society rules, as applicable.
- Radar systems onboard offshore installations should provide 360° coverage and should be capable of detecting all potential marine hazards (e.g., vessels, drifting objects and during ice season, icebergs (including small pieces of ice - bergy bits, growlers - and icebergs in pack ice, as standard marine radar systems do not have this capability)).

- Appropriate radar plotting equipment should be provided with alarms to notify personnel on watch of impending targets.
- A continuous radar watch should be maintained at all times by a competent person. For drilling, production and accommodations installations, additional guidance on radar training is provided in the COP TQOP.
- If there is a possibility for a collision with an unmanned installation that could result in a spill, the risk assessment should consider installation of a radar and remote monitoring by a competent person.
- Refer to requirements and associated guidance for operations and maintenance of these systems under sections 153, 156, 157 and 158 of the *Framework Regulations*.

Section 129 - Communication System

129 (1) An operator must ensure that an installation is equipped with a communication system that has built-in redundancy and is capable of communicating continuously, including in an emergency, with
(a) external emergency response teams;
(b) all persons, individually or collectively, at an operations site;
(c) all persons who are in transit to or from an operations site;
(d) all support craft;
(e) all onshore support centres;
(f) nearby vessels and aircraft; and
(g) nearby installations.

Radiocommunication system

(2) An operator must ensure that an installation other than an unattended installation is equipped with a radiocommunication system in respect of which the following requirements are met:
(a) the system must comply with Part 2 of the Navigation Safety Regulations, 2020 as if the installation were a Canadian vessel to which those Regulations apply;
(b) a technical acceptance certificate must have been issued in respect of the system under the Radiocommunication Act; and
(c) a continuous listening watch and radio log must be maintained.

Radiocommunication system – unattended installation

(3) An operator must ensure that any radiocommunication system on an unattended installation meets the requirements referred to in paragraphs (2)(a) and (b).

a. General

- Refer to the requirements and associated guidance for emergency alert systems under section 23 of the *OHS Regulations*.
- Refer to the requirements and associated guidance for electrical systems under section 122 of the *Framework Regulations*. Guidance for communication equipment is included in the standards referenced within this section.
- Refer to the requirements and associated guidance for communications with lifeboats and aircraft under subsection 119(8) and section 174 of the *Framework Regulations*, respectively.
- Refer to the requirements of the *Radiocommunication Act* and associated regulations, and the associated guidance for radiocommunication equipment on ISEDC's website. This Act applies to any shore-based installations and to vessels and aircraft. Pursuant to paragraph 3(3)(c) of the *Radiocommunication Act*, this should be interpreted to apply to any fixed platform and to floating platforms that are moored, tethered or otherwise connected to the seabed via drill pipe, production or drilling riser, etc. Any questions or exemptions from requirements should be directed to the ISEDC.
- Refer to SOLAS and associated IMO resolutions and circulars for guidance on the installation, operation and maintenance of radiocommunication systems.
- Refer to flag state and classification society rules.
- A redundant means of internal communication should be available between control rooms, control stations and other key areas onboard an installation.
- As portable radios can be used anywhere onboard an installation, including during an emergency, the equipment should be intrinsically safe to prevent it from being a source of ignition.
- Paragraph 129(2)(a) of the *Framework Regulations* also applies to any EPIRB or SART that may be installed in lifeboats.
- Additional guidance is provided in the following:
  - *ISO 15544 Oil and gas industries - Offshore production installations - Requirements and guidelines for emergency response.*
  - *ISO 35102 Petroleum and natural gas industries – Arctic operations – Escape, evacuation and rescue from offshore installations.*

b. Radio Inspection Certificates

With respect to paragraph 129(2)(a) of the *Framework Regulations*, the following is noted:

- All installations, whether fixed, foreign floating or Canadian floating require a radio inspection certificate (i.e., either safety convention or domestic) to be issued in accordance with the *Navigation Safety Regulations.*
- Radiocommunication equipment installed at an operation site should be suitable for the area for which it is being operated (e.g., area A3) and the type of area should be noted on associated radio inspection certificates.
- As most radio inspection certificates issued do not cover aeronautical VHF radiotelephone stations, associated radiocommunication equipment and procedures for communication, then these systems and procedures should comply with the requirements of the *Canadian*

Aviation Regulations and be acceptable to Transport Canada Aviation. Additional certification may need to be provided to demonstrate that aeronautical equipment is covered.

c. Technical Acceptance Certificates

With respect to paragraph 129(2)(b) of the *Framework Regulations*, each item of radiocommunication equipment, including both maritime and aeronautical, should be listed on ISEDC's Radio Equipment List and certified for use in Canada by an ISEDC-recognized certification body. Any questions or exemptions with respect to these requirements should be submitted to ISEDC.

d. Radio Licences

- Radiocommunication systems must be licensed in accordance with the *Radiocommunication Act* and associated regulations, and this should be interpreted to apply to any shore-based installations.
- Information on aircraft radio station licensing, ship radio station licensing, and other radio licenses is provided on the ISEDC website.

e. Competency

With respect to paragraph 129(2)(a) of the *Framework Regulations*, requirements for radio operators and their associated communication processes are located in the *Navigation Safety Regulations*, and may be found in the *Canadian Aviation Regulations* for communications with aircraft. For drilling, production and accommodations installations, additional guidance on training for radio operators, telecommunication technicians and other personnel who communicate with search and rescue services is provided in the COP TQOP.

f. Operations and Maintenance

Refer to requirements and associated guidance for operations and maintenance of these systems under sections 153, 156, 157 and 158 of the *Framework Regulations*.

Section 130 - General Alarm System

130 (1) An operator must ensure that an installation is equipped with a general alarm system that is capable of alerting persons on the installation of any hazards to safety or the environment other than fire or gas.

Additional requirements

(2) The operator must ensure that the general alarm system is

(a) operational at all times other than when the system is being inspected, maintained or repaired;
(b) flagged as being subject to inspection, maintenance or repair, as required; and
(c) designed to prevent tampering.

Alternative means of alert

(3) If a general alarm system is being inspected, maintained or repaired, the operator must ensure that there is an alternative means of alerting persons of the hazards referred to in subsection (1).

- Refer to the requirements and associated guidance for emergency alert systems under section 23 of the *OHS Regulations*.
- Refer to the requirements and associated guidance for electrical systems and fire and gas detection systems under sections 122 and 132 of the *Framework Regulations.* Guidance for general alarm systems is also provided in the standards referenced in section 123 of this Guideline.
- Refer to SOLAS and associated IMO resolutions and circulars for guidance on the installation, operation and maintenance of general alarm systems.
- Refer to flag state and classification society rules.
- The general alarm system, including the prepare to abandon alarm, should be audible and visible in all areas of the installation.
- To the extent practicable, audible and visual alarms in an operating region should be standardized, reflecting the fact that personnel may occasionally work on more than one installation.
- In addition to the standards referenced under section 23 of the *OHS Regulations* for all marine installations or structures, additional guidance is provided in the following:
  - MODU Code
  - *ISO 15544 Oil and gas industries - Offshore production installations -- Requirements and guidelines for emergency response*
  - *ISO 13702 Petroleum and natural gas industries - Control and mitigation of fires and explosions on offshore production installations - Requirements and guidelines*
  - *ISO 35102 Petroleum and natural gas industries – Arctic operations – Escape, evacuation and rescue from offshore installations*
  - *NORSOK S-001 Technical Safety* contains guidance for general alarm systems and references to standards for the management of alarm systems.
- Refer to requirements and associated guidance for operations and maintenance of these systems under sections 153, 156, 157 and 158 of the *Framework Regulations*.

Section 131 - Gas Release Systems

131 (1) An operator must ensure that an installation that includes process tanks, process vessels and piping is equipped with a gas release system that has a flaring system, a pressure relief system, a depressurizing system or a cold vent system.

Risk assessment - design

(2) The operator must ensure that the design of the gas release system is based on the results of the risk assessment conducted under subsection 107(1).

Design

(3) The operator must ensure that the gas release system is designed to
(a) release gas and combustible liquid from an installation in a controlled manner without creating a hazard to safety;
(b) reduce pressure in the entire process system as quickly as possible while ensuring a safe and controlled release of pressure;
(c) minimize the effect on the environment;
(d) be activated from the main control centre and from control stations that meet the requirements set out in subsection (5); and
(e) ensure that oxygen cannot enter the system during normal operations.

Location — system

(4) The operator must ensure that the gas release system is designed and located taking into account factors, including physical and environmental conditions, that affect the safe and normal flaring or emergency release of combustible liquid, gases or vapours so that when the system is in operation it does not damage the installation - or any other installation, vessel or support craft in proximity to it - or injure any person.

Control stations

(5) The operator must ensure that the control stations from which the gas release system is activated are located and spaced so that they remain protected and accessible for safe operation of the system.

Flaring systems

(6) The operator must, in respect of any flaring system, ensure that
(a) if an unlit release of gas could produce toxic gas concentrations or gas concentrations of more than 50% of the lower explosive limit of the released gas,

(i) the system has an automatic igniter system that has redundancy in its ignition capabilities, and
(ii) in the case of an open flare system, the system and any associated equipment are designed to ensure a continuous flame; and
(b) the system and any associated equipment are designed to
(i) withstand the radiated heat at the maximum flaring rate;
(ii) prevent flashback; and
(iii) withstand all loads to which they may be subjected.

Risk minimization — vents

(7) The operator must ensure that any vent that is used to release gas into the atmosphere without combustion is designed and located in accordance with the measures referred to in clause 9(2)(b)(vi)(A) and subparagraph 10(2)(b)(vi) that are described in the operator's safety plan and environmental protection plan, respectively.

Liquid removal

(8) The operator must ensure that any liquid, other than water, that cannot be safely and reliably burned at the flare tip of a gas release system is removed from the gas before it enters the flare.

General

- Refer to the requirements and associated guidance for physical and environmental conditions, risk assessments, hazardous and non-hazardous areas, ventilation, ignition prevention, electrical systems, control and monitoring systems, emergency shutdown systems, pressure systems, mechanical equipment and formation flow test equipment in sections 98, 104, 106, 107, 108, 110, 113, 114, 115, 122, 123, 124, 125, 133, 135, 136, 167 and 169 of the *Framework Regulations*.
- Refer to the requirements and associated guidance for formation flow test programs and gas flaring and venting under sections 63, 82, 83 and 84 of the *Framework Regulations*. Any flaring or venting should be in accordance with any conditions or commitments of *Development Plans* and in any Decision issued by the Minister of ECCC for the associated Environmental Assessment and Impact Assessment in respect of that program, or for a drilling program in NL, for exploratory drilling, the *Regulations Respecting Excluded Physical Activities (Newfoundland and Labrador Offshore Exploratory Wells*), as the case may be. Flaring and venting should also be in accordance with commitments made in the accepted Environmental Protection Plan.
- Refer to the requirements and associated guidance for thermal stress and sound levels under section 40 and Part 15 of the *OHS Regulations*, respectively.
- This section applies to all installations that are equipped with a pressure relief/cold vent system for gas or combustible liquids (including mud gas separators onboard a drilling

installation) and also applies to a drilling installation when it is actively engaged in formation flow testing that involves the use of a gas release system.

- With respect to paragraph 131(6)(a) of the *Framework Regulations*, this is intended to be measured at the flare tip. It is also interpreted that an acceptable means of automatic activation can be from a pushbutton in the control room as long as there is a reliable means to detect flame-out and it is activated immediately upon detection. In addition, it is also noted that "redundancy" in its ignition capabilities does not necessarily mean that more than one automatic ignition system is required.
- Risk assessments should be supplemented with studies on noise, thermal radiation, computational fluid dynamics and gas dispersion analysis.
- Operators should make every effort to reduce the volume of flaring and venting to as low as reasonably practicable and should consider designing, selecting or modifying installations to eliminate or reduce gas flaring and venting to as low as reasonably practicable. Measures to reduce high flare gas volumes during the early stages of production and during process upsets should be considered and include any measures to improve the reliability and availability of related equipment and systems. Measures should also be implemented to reduce the volume of flaring and venting when inspection, testing, maintenance and repair activities are being undertaken.
- The permanent or temporary addition of equipment or changes to process may have an impact on the associated risk assessments and the effectiveness and operability of these systems. These changes should be assessed through a formal management of change process to determine if the existing measures implemented within this section will continue to be appropriate following a change.

Standards

- Additional guidance for gas release systems is provided in the following:
    - *ISO 13702 Petroleum and natural gas industries – Control and mitigation of fires and explosions on offshore production installations – Requirements and guidelines.*
    - *NORSOK S-001 Technical Safety.*
    - *API Std 521 Pressure-relieving and Depressurizing Systems.*
    - *API Std 537 Flare Details for Petroleum, Petrochemical and Natural Gas Industries* and in particular, the annex for offshore flare systems.
    - *IOGP Specification S-722 Supplementary Specification to API Std 537 Flare Package*
    - Flag state and classification society rules.
    - Section 5.8 and Appendix E of *API RP 14G Recommended Practice for Fire Prevention and Control on Fixed Open-type Offshore Production Platforms.*
    - *ISO 10418 Petroleum and natural gas industries – Offshore production installations – Process Safety Systems.*
    - *API RP 14C Analysis, Design, Installation, and Testing of Safety Systems for Offshore Production Facilities* for discharging H_2S to the atmosphere.
    - *API Std 2000 Venting Atmospheric and Low-pressure Storage Tanks* for guidance on venting.

- *DNV-OS-E201 Oil and gas processing systems* which includes guidance on flare gas recovery systems (e.g., closed flare systems).

Operational Considerations

- Refer to requirements and associated guidance for operations and maintenance of these systems under sections 73, 153, 156, 157 and 158 of the *Framework Regulations*.
- With respect to section 110 of the *Framework Regulations*, associated inspection, testing, maintenance or replacement of flaring systems (e.g., inspection or replacement of flare tips) should consider both safe access and the potential risk of dropped objects from persons, aircraft or RPAS while these activities are being undertaken.
- With respect to paragraphs 131(3)(d) and (6)(a)(i) of the *Framework Regulations*, the use of a gun as a redundant ignition capability to manually ignite a pilot is not considered to be in compliance with these regulations.
- The effects of thermal radiation on equipment should include consideration of the effects on all safety-critical elements and associated support systems. In addition, systems that have been designed to provide fire protection for a set timeframe may degrade prematurely if prolonged continuous flaring is required.

Section 132 - Fire and Gas Detection

132 (1) An operator must ensure that an installation is equipped with a fire and gas detection system.

Requirements

(2) The operator must ensure that the fire and gas detection system
(a) provides continuous, reliable and automatic monitoring functions to allow persons to be alerted to the presence and location of fire and hazardous gas, as well as the concentration and composition of that gas;
(b) as far as is practicable, is functionally and physically independent of other essential systems or, if that is not practicable, is arranged so as not to adversely affect or be adversely affected by the operation of those systems;
(c) includes an alarm system, with audible and visual alarms that are distinct from other types of alarms, that can be heard or seen at the main control centre and in other areas where persons are normally present, that are, on detection of fire and gas hazards, automatically activated and that can also be manually activated; and
(d) allows control measures, including those that are designed to be initated automatically, to be initiated manually to prevent abnormal conditions from escalating and causing major accidental events.

Risk assessment — design

(3) The operator must ensure that the design of the fire and gas detection system is based on the results of the risk assessments conducted under subsection 107(1).

Design

(4) The operator must ensure that the fire and gas detection system is designed
(a) to detect the types of fire and hazardous gas releases identified in the risk assessment conducted under subsection 107(1);
(b) to detect hazardous gas and smoke in the air intakes of any mechanically ventilated non-hazardous areas; and
(c) such that the means to manually initiate fire and gas alarms are available at or near the office of the installation manager, at the main control centre, at every control station and at other locations identified in the risk assessment conducted under subsection 107(1).

Requirements

(5) The operator must ensure that the fire and gas detection system meets the following requirements:
(a) its detection components must
> ***(i) be capable of detecting the types of fire or hazardous gas releases identified in the risk assessment conducted under subsection 107(1) in the areas in which they are located,***
> ***(ii) ensure reliable and early detection, taking into account their response characteristics, redundancy and performance under foreseeable conditions in which detection may be required,***
> ***(iii) be rated and maintained for use in the areas in which they are located, as those areas are classified in accordance with the classification system referred to in subsection 113(2), and***
> ***(iv) include failure and malfunction indicators;***

(b) the system and its components must be protected from mechanical damage and damage caused by fire, explosion and physical and environmental conditions to which they may be exposed so that they remain capable of fulfilling their intended functions under all foreseeable operating conditions;
(c) the system must allow for all necessary information to be continuously provided to the main control centre and other strategic locations to permit the management of emergency situations; and
(d) the system must be capable of being reset only if the cause of its activation has been resolved.

Testing and maintenance

(6) The operator must ensure, in relation to the testing and maintenance of the fire and gas detection system, that the following requirements are met:
(a) the system must be capable of being overridden for the purposes of testing and maintenance activities;
(b) override commands and functions must be applied for the shortest amount of time possible and with as few as possible being applied simultaneously; and
(c) the testing and maintenance activities must not impair the system beyond what is necessary to undertake those activities and must not impede its functioning.

Work permit

(7) A work permit is required for the testing and maintenance of the fire and gas detection system.

Management of override effects

(8) The work permit must set out measures to be taken to manage the effects of overriding the fire and gas detection system.

Leak repair

(9) The operator must ensure that any leak of gas that is detected by the fire and gas detection system or by means of an auditory, olfactory or visual method - including the observation of the dripping of hydrocarbon liquids from an equipment component —is repaired
(a) immediately, if the repair is necessary for the purposes of safety or the conservation of petroleum resources; or
(b) as soon as the circumstances permit, in any other case.

General

- Refer to the requirements and associated guidance for emergency alert systems and personal gas monitoring devices under sections 23, 28 and 48 and paragraphs 46(i) and 157(1)(b) of the *OHS Regulations*.
- Refer to the requirements and associated guidance for fire, explosion and hazardous gas risk assessments under section 107 of the *Framework Regulations*.
- Refer also to the requirements and associated guidance for passive fire protection (for automatic functions), ventilation, electrical systems, general alarm systems, emergency shutdown systems and fire protection systems under sections 98, 110, 112, 114, 122, 130, 133 and 134 of the *Framework Regulations*.
- With respect to paragraph 132(2)(a) of the *Framework Regulations*, detectors should be able to identify the representative gas (e.g., H_2S, methane, methanol, hydrogen) and the associated concentrations for that specific gas.

- Refer to flag state and classification society rules, noting that additional consideration should be given to the associated fire, explosion and hazardous gas risk assessment, the executive actions that should occur (such as automatic shutdown of ventilation systems and dampers based on confirmed gas detection) and the redundancy in the detection systems to ensure continued operation.
- The permanent or temporary addition of equipment or flammable or combustible materials in an area, whether it be permanent or temporary, may have an impact on the associated risk assessments and the types of fire and gas detection systems provided. It may also impact the functioning of this equipment. These changes should be assessed through a formal management of change process to determine if the existing measures implemented within this section will continue to be appropriate following a change.
- If portable type detectors (e.g., rig rats) or other temporary installation methods are used as a replacement for a permanent fire and gas detection system, they must be demonstrated to be in compliance with the regulations.
- Distinct audible and visual alarms for both hydrocarbon and toxic gases should be installed in areas where persons may be present to alert them of these particular hazards. They should be separate and distinguishable from the general alarm system and from each other, as applicable. In addition, refer to guidance on automatic visual warning systems for aircraft under section 174 of the *Framework Regulations*.
- Refer to requirements and associated guidance for operations and maintenance of these systems under sections 153, 156, 157 and 158 of the *Framework Regulations*.

Standards

- Additional guidance is provided in the following:
    - *ISO 13702 Petroleum and natural gas industries - Control and mitigation of fires and explosions on offshore production installations - Requirements and guidelines,* with the following notes:
        - This standard does not cover the requirements for toxic gas detection and the response to toxic gas situations; therefore, alternative standards would have to be selected for these systems.
        - This standard does not cover specifics in relation to the design, voting logic or suggested set points or specifics in relation to inspection, testing and maintenance of these systems so other standards should be considered in addressing these aspects.
    - *NORSOK S-001 Technical Safety* - Guidance is also provided on voting logic, installation of early warning smoke detection systems in certain applications and associated alarm set points for different configurations and gases (e.g., hydrocarbon, H_2S, CO, CO_2, oxygen deficiency).
    - Guidance on gas detection systems is provided in *IEC 60079-29-2 Explosive Atmospheres - Part 29-2: Gas detectors — Selection, installation, use and maintenance of detectors for flammable gases and oxygen.*
    - Guidance for hydrocarbon, H_2S and fire detection systems is provided in the API standards referenced in section 122 of the *Framework Regulations*.

- Guidance for toxic (e.g., H_2S) gas detection systems and placement of fusible plugs in process areas is provided in *API RP 14C Analysis, Design, Installation, and Testing of Safety Systems for Offshore Production Facilities*.
- Guidance for the installation, testing and maintenance of detection systems is provided in *NFPA 72 National Fire Alarm and Signaling Code*.
- Guidance for fire detection systems, gas detection systems and CO detection systems is also included in *NFPA 1 – Fire Code* and *NFPA 101 Life Safety Code.*

Section 133 - Emergency Shutdown System

133 (1) An operator must ensure that an installation has an emergency shutdown system that is capable of
(a) shutting down all potential ignition sources and potential sources of flammable liquids or gases, including by isolating those sources;
(b) depressurizing all potential sources of flammable liquids or gases other than reservoirs;
(c) preventing abnormal conditions from escalating and causing major accidental events; and
(d) limiting the extent and duration of any major accidental event.

Studies and assessments — design

(2) The operator must ensure that the design of the emergency shutdown system is based on studies, analyses and assessments that identify potential hazards and must assess the risks associated with those hazards, including the risk assessment conducted under subsection 107(1) and the risk and reliability analyses referred to in section 108.

Design

(3) The operator must ensure that the emergency shutdown system is designed to
(a) allow for automated and manual activation to ensure effective shutdown;
(b) allow for the shutdown of any system or equipment to bring it to a safe state, unless the system or equipment has been rated to remain operational in the area in which it is located, as that area is classified in accordance with the classification system referred to in subsection 113(2);
(c) allow for the selective shutdown of ventilation systems, other than fans that are necessary for supplying combustion air to engines that are required to operate during emergency situations unless gas has been detected in the intake to those engines;
(d) allow for the isolation of petroleum and flammable fluid inventories, including reservoirs, wells, production systems and pipelines, from ignition sources;
(e) take into account the size and segregation of petroleum and flammable fluid inventories to limit the quantity of substances released on loss of containment;
(f) allow for the depressurization and the disposal of hydrocarbon inventories in a safe manner and to a safe location without cold venting;

(g) allow for the closure of the installation's subsea and subsurface safety valves and of pipeline safety valves;
(h) take into account, in relation to all essential systems, the necessary timelines to support the safe escape, refuge and evacuation of persons and to maintain the integrity of the installation; and
(i) take into account the activation of fixed fire-suppression systems required under paragraph 134(4)(a).

Shutdown Logic

(4) The operator must ensure that the logic for the emergency shutdown system includes a hierarchy of shutdown levels, action sequences and timelines that are appropriate for the degree of risk posed by the hazards identified in the studies, analyses and assessments referred to in subsection (2).

Additional requirements

(5) The operator must ensure, in relation to the emergency shutdown system, that
(a) the system is reliable and, as far as is practicable, it is functionally and physically independent of other essential systems or, if that is not practicable, it is arranged so as not to adversely affect or be adversely affected by the operation of those systems;
(b) the system includes an alarm system, with audible and visual alarms that are distinct from other types of alarms, that will automatically activate in the main control centre and at other strategic locations so that all affected persons, having regard to the hierarchy of shutdown levels referred to in subsection (4), are alerted to the emergency shutdown;
(c) there is continuous monitoring from the main control centre of the system's status, including, if the system or part of the system is overridden, the extent and duration of the override;
(d) the system and its components are protected from mechanical damage and damage caused by fire, explosion and physical and environmental conditions to which they may be exposed so that they remain capable of fulfilling their intended functions under all foreseeable operating conditions;
(e) the system allows for all information that is necessary to permit the management of emergency situations to be continuously provided to the main control centre and other strategic locations, including information regarding
  (i) the shutdown level and the source of activation of the system,
  (ii) any shutdown effects that failed to execute on activation of the system, and
  (iii) the status, including failure, of the system's components;
(f) the system is capable of being activated from multiple manual activation points that are
  (i) clearly marked,
  (ii) protected against unintentional activation, and
  (iii) located at

(A) in the case of manual activation points for the highest level of shutdown, the main control centre and other strategic locations, including aircraft landing areas and other embarkation stations, and

(B) in the case of all other manual activation points, strategic positions, at least one of which must not be in a hazardous area;

(g) the activation of the system from a manual activation point triggers the general alarm system referred to in section 130;

(h) if any part of the system is operated using a hydraulic or pneumatic accumulator,

(i) the accumulator

(A) is located as close as is practicable to the part that it is intended to operate, except if that part is part of a subsea production system, and

(B) has the capacity for a sufficient number of activations to ensure that shutdown can be achieved, and

(ii) the shutdown valves revert to a fail-safe mode in the event of a failure of the accumulator;

(i) the system is capable of testing both its input and output signal devices and its internal functions to ensure its functioning;

(j) in the event of failure of the main electrical power supply referred to in subsection 122(4), the system has the capacity to function continuously until the main electrical power supply is restored or all shutdown operations have been concluded;

(k) in the event that an impairment of the system or any of its components increases the risk to safety or the environment, any other systems that support the emergency shutdown system reverts to a fail-safe mode;

(l) if two or more installations are connected or if there is temporary equipment that has an emergency shutdown system on an installation,

(i) the emergency shutdown systems of the connected installations are linked so that emergency shutdown signals are transmitted between those systems,

(ii) the emergency shutdown systems of the temporary equipment are linked to the installation's emergency shutdown system so that emergency shutdown signals are transmitted between those systems, and

(iii) the logic for the emergency shutdown system of each of the connected installations and of the temporary equipment is re-evaluated and modified, if necessary, to take into account the fact that the emergency shutdown systems are linked, with the logic of the installation's emergency shutdown system being given priority over that of any temporary equipment;

(m) the system is capable of being overridden or reset only if the cause of its activation has been resolved and there has been local confirmation that the equipment that gave rise to the system shutdown can be safely used; and

(n) override commands and functions are not capable of being unintentionally activated.

Testing and maintenance

(6) If the emergency shutdown system is capable of being overridden for the purposes of testing and maintenance activities, the operator must ensure that the following requirements are met:

(a) override commands and functions must be applied for the shortest amount of time possible and with as few as possible being applied simultaneously; and
(b) the testing and maintenance activities must not impair the system beyond what is necessary to undertake those activities and must not impede the system's functioning.

Work permit

(7) A work permit is required for the testing and maintenance of the emergency shutdown system.

Management of override effects

(8) The work permit must set out the measures to be taken to manage the effects of overriding the emergency shutdown system.

Closure — subsurface safety valve

(9) In the case of a production installation, the operator must ensure that, if the emergency shutdown system is activated, any subsurface safety valve closes not later than two minutes after the tree safety valve has closed unless a longer delay is justified by the mechanical or production characteristics of the well.

General

- Refer to the requirements and associated guidance for risk assessments, hazardous and non-hazardous areas, ventilation, ignition prevention, electrical systems, control and monitoring systems, general alarm systems, gas release systems, fire and gas detection systems, fire protection systems, pressure systems, mechanical equipment, subsea production systems and formation flow testing equipment in sections 98, 107, 108, 110, 113, 114, 115, 122, 123, 124, 125, 130, 131, 132, 134, 135, 136, 138, 167 and 169 of the *Framework Regulations*. These sections reference the formal risk assessments to be undertaken, the inputs for initiation of the emergency shutdown system and the associated executive actions stemming from its activation.
- Refer to requirements and associated guidance for operations and maintenance of these systems under sections 153, 156, 157 and 158 of the *Framework Regulations*.
- Refer to flag state and classification society rules.
- The addition of permanent or temporary equipment may have an impact on the associated risk assessments that have been undertaken and compliance to these regulations. These changes should be assessed through a formal management of change process to determine if the existing measures implemented within this section will continue to be appropriate following a change.
- All components of the emergency shutdown and depressurizing system, including critical emergency shutdown valves, emergency depressurization valves, actuators and supply

systems, emergency depressurization piping, flare knockout drums and supports should be located, designed and protected to withstand all credible major accidental loads (e.g., fire, explosion, dropped objects) until they have performed their function.

Standards

Guidance is provided in the following references:

- *ISO 13702 Petroleum and natural gas industries - Control and mitigation of fires and explosions on offshore production installations - Requirements and guidelines*.
- *NORSOK S-001 Technical Safety* which also contains guidance on manual activation points, hierarchal levels of shutdown, emergency shutdown valves and executive actions.
- Other standards that should be considered with respect to specific aspects include:
  - Guidance for emergency shutdown systems on production installations is provided in *ISO 10418 Petroleum and natural gas industries – Offshore production installations – Process Safety Systems.*
  - Guidance is provided in *API RP 14C Analysis, Design, Installation, and Testing of Safety Systems for Offshore Production Facilities*. However, this standard should be used along with other standards for the following reasons:
    - It does not require the emergency shutdown system to be automatic.
    - It does not require components that stay live, such as fire and gas detection systems, to be rated for operation in a hazardous environment.
    - It does not discuss the isolation or rating of electrical equipment that stays live following an emergency shutdown.
    - Except for requiring manual emergency shutdown stations, it does not discuss systems outside of the process plant (e.g., cargo tanks).
  - Guidance on depressurizing systems is provided in *API Std 521 Pressure-relieving and Depressurizing Systems.*
  - Guidance on emergency depressurizing design is provided in section 5.8 and Appendix E of *API RP 14G Recommended Practice for Fire Prevention and Control on Fixed Open-type Offshore Production Platforms.*

Section 134 - Fire Protection Systems and Equipment

134 (1) An operator must ensure that an installation is equipped with fire protection systems and equipment to control and extinguish fires.

Safety plan

(2) The operator must ensure that the fire protection systems and equipment are designed, selected, operated, inspected, tested and maintained in accordance with the measures referred to in clause 9(2)(b)(vi)(B) that are described in the operator's safety plan.

Design and selection

(3) The design and selection of fire protection systems and equipment, including suppression agents, must take into account their intended use and the results of the risk assessment conducted under subsection 107(1).

Further requirements

(4) The operator must ensure that the fire protection systems and equipment include
(a) automated fixed fire suppression systems that are capable of being manually activated from outside the space that is being protected;
(b) fixed monitors, deluge systems and foam systems;
(c) manual firefighting systems and equipment; and
(d) any redundancies that are necessary to ensure the systems function in the case of a failure of one of their components.

Protection from damage

(5) The operator must ensure that the fire protection systems and equipment are protected from mechanical damage and damage caused by fire, explosion and physical and environmental conditions to which they may be exposed so that they remain capable of fulfilling their intended functions under all foreseeable operating conditions.

Fixed fire suppression system

(6) The operator must ensure that an automated fixed fire suppression system is installed in every accommodations area and hazardous area and in any other area that requires such a system based on the results of the risk assessment conducted under subsection 107(1).

Fire pumps

(7) The operator must ensure that at least two dedicated, segregated and independently driven fire pumps supply a dedicated firewater ring main and that each of those fire pumps is
(a) equipped with at least two independent starting devices; and
(b) designed to allow for both local and remote control.

Location

(8) The operator must ensure that the fire pumps are located as far as possible from equipment used for storing and processing petroleum, taking into account the results of the risk assessment conducted under subsection 107(1).

Supply of firewater

(9) The operator must ensure that the fire pumps and piping and their valves are capable of providing a sufficient supply of firewater to any area on the installation, including if a segment of the firewater ring main is damaged.

Firewater system

(10) The operator must ensure that the firewater system is capable of operating continuously for a minimum of 18 hours.

Fire hydrants and hose reels

(11) The operator must ensure that the number and location of fire hydrants and fire hose reels are such that at least two jets of water, not emanating from the same location, can reach any part of the installation where a fire may occur.

Portable fire-extinguishing equipment

(12) In areas where it is not practical to use fire hydrants and fire hose reels, the operator must ensure that portable fire-extinguishing equipment is readily available and accessible.

Alarms at main control centre

(13) The operator must ensure that audible and visual alarms will activate at the main control centre on the initiation of any of the automated fixed fire suppression systems or on the loss of any firewater pressure.

Additional alarms

(14) If the automated fixed fire suppression system creates a hazard to persons, the operator must ensure that audible and visual alarms automatically activate inside and outside the space that is being protected.

Unattended installations

(15) Paragraphs (4)(a) and (b) and subsections (6) to (11) do not apply to unattended installations.

General

- Refer to the requirements and associated guidance for fire and explosion, firefighting equipment and fire team equipment under sections 26, 27 and 28 of the *OHS Regulations*.
- Refer to the requirements and associated guidance for physical and environmental conditions, risk assessments, ignition prevention, pressure systems, mechanical systems,

electrical systems, control and monitoring systems, general alarm systems, fire and gas detection systems, emergency shutdown systems, pressure systems and mechanical equipment under sections 98, 104, 106, 107, 108, 110, 115, 122, 123, 124, 130, 132, 133, 135, 136 and 169 of the *Framework Regulations*.

- For fire protection systems for landing areas, refer to the requirements and associated guidance under section 174 of the *Framework Regulations*.
- Refer to requirements and associated guidance for operations and maintenance of these systems under sections 153, 156, 157 and 158 of the *Framework Regulations*.
- With respect to paragraph 134(4)(a) of the *Framework Regulations*, it is interpreted that fixed fire suppression systems that are wet water systems operating with a frangible bulb do not require manual activation from outside the space that is being protected. These systems should have flow detection and appropriately rated frangible bulbs installed, and be accompanied by appropriate fire detection in those areas in which they are installed.
- With respect to subsection 134(6) of the *Framework Regulations*, it is interpreted by the *Regulator* that if the risk assessment under subsection 107(1) of the *Framework Regulations* determines all of the measures combined do not reduce the risk of a fire or explosion to as low as reasonably practicable in the areas noted in this provision, an automated fixed fire suppression system must be installed in those areas. With respect to accommodations areas, if an automated fixed fire suppression system is not installed, consideration will be given to the additional measures (e.g., enhanced fire detection and monitoring, enhanced segregation, enhanced fire divisions, control of materials and ignition sources, distribution of hose reels/hydrants and extinguishers, increased frequency of maintenance and testing of detection system, associated emergency response drills) in place. Additional guidance is provided in *OEUK Good Practice in Fire Management in Offshore Accommodation*.

Scope

- This section is intended to cover the following types of fire protection systems and equipment:
    - Firewater and foam supply systems
    - Deluge systems
    - Hose reels
    - Monitors
    - Hydrants
    - General and local fire suppression systems
    - Fire extinguishers

Other Considerations

The addition of permanent or temporary equipment or flammable or combustible materials in an area may have an impact on the associated risk assessments that have been undertaken and the types and quantity of fire protection equipment provided. It may also impact on the availability or access that is provided to this equipment. These changes should be assessed through a formal management of change process to determine if the existing measures implemented within this section will continue to be appropriate following a change.

Standards

Guidance for fire protection systems and equipment can be found in the following references:

- Flag state and classification society rules.
- *ISO 13702 Petroleum and natural gas industries - Control and mitigation of fires and explosions on offshore production installations - Requirements and guidelines.*
- *NORSOK S-001 Technical Safety*.
- *NFPA 1 – Fire Code, NFPA 101 Life Safety Code*, *NFPA 30 Flammable and Combustible Liquids Code* and other NFPA standards contain guidance for the selection, design, installation, operation and maintenance of fire protection systems and in particular, some standards contain guidance for marine system applications. Some common NFPA standards used in the offshore petroleum industry include:
    - *NFPA 10 Standard for Portable Fire Extinguishers*
    - *NFPA 11 Standard for Low-, Medium-, and High-Expansion Foam*
    - *NFPA 12 Standard on Carbon Dioxide Extinguishing Systems*
    - *NFPA 13 Standard for the Installation of Sprinkler Systems*
    - *NFPA 14 Standard for the Installation of Standpipe and Hose Systems*
    - *NFPA 15 Standard for Water Spray Fixed Systems for Fire Protection*
    - *NFPA 17 Standard for Dry Chemical Extinguishing Systems*
    - *NFPA 17A Standard for Wet Chemical Extinguishing Systems*
    - *NFPA 20 Standard for the Installation of Stationary Pumps for Fire Protection*
    - *NFPA 24 Standard for the Installation of Private Fire Service Mains and Their Appurtenances*
    - *NFPA 25 Standard for the Inspection, Testing and Maintenance of Water-Based Fire Protection Systems*
    - *NFPA 110 Standard for Emergency and Standby Power Systems*
    - *NFPA 750 Standard on Water Mist Fire Protection Systems*
    - *NFPA 1961 Standard on Fire Hose*
    - *NFPA 1962 Standard for the Care, Use, Inspection, Service Testing, and Replacement of Fire Hose, Couplings, Nozzles, and Fire Hose Appliances*
    - *NFPA 2001 Standard on Clean Agent Fire Extinguishing Systems*
- Also, the following should be considered:
    - *IOGP Specification S-719 Supplementary Specification to NFPA 750 Water Mist Fire Protection Systems.*
    - *HSE Offshore Information Sheet No.1/2010 Water deluge systems: Testing and performance measurements*.

Section 135 - Boilers and Pressure Systems

135 (1) An operator must ensure that boilers and pressure systems are designed in accordance with the measures referred to in clause 9(2)(b)(vi)(C) that are described in the operator's safety plan.

Design requirements

(2) The boilers and pressure systems must be designed to
(a) prevent the occurrence of an abnormal condition that could cause an undesirable event;
(b) prevent an undesirable event from causing a release of liquids, gases or vapours;
(c) prevent the ignition of any flammable liquids, gases or vapours that are released;
(d) safely disperse or dispose of any liquids, gases or vapours that are released;
(e) prevent the formation of explosive mixtures;
(f) limit persons' exposure to fire hazards;
(g) monitor safe limits of pressure, temperature and fluid levels and reliably protect against exceeding those limits;
(h) permit the examination of components critical to the pressure system to ensure their continued integrity;
(i) allow for draining and venting at all stages of operation to
> ***(i) permit cleaning, inspection and maintenance activities to be carried out safely, and***
> ***(ii) avoid harmful effects, including water hammer, vacuum collapse, corrosion and uncontrolled chemical reactions;***

(j) prevent the escalation in relation to the boilers and pressure systems of accidental events occurring outside of them; and
(k) limit and mitigate the effects of any loss of containment of the contents of the boilers and pressure systems.

Additional requirements

(3) The design of boilers and pressure systems must
(a) be based on standards that incorporate safety margins, that conform to good engineering practice and that involve the carrying out of analyses and numerical modelling as necessary to determine the behaviour and failure modes of the boilers and pressure systems under all foreseeable operating conditions, taking into account
> ***(i) the internal and external pressures to which the boilers and pressure systems are subjected,***
> ***(ii) ambient and operating temperatures,***
> ***(iii) static pressure and the mass of the contents of the boilers and pressure systems when tested or operated,***
> ***(iv) foreseeable dynamic loads and reaction forces and moments resulting from, among other things, piping and its supports and other accessories,***
> ***(v) structural and mechanical integrity threats, and***

(vi) reactions caused by changes in fluids and other substances contained in the boilers and pressure systems over time, including reactions caused by the products of the decomposition of unstable fluids or substances;

(b) if hazards cannot be eliminated, incorporate safety measures that take into account

(i) the need for closing and opening devices and devices to indicate their status and to prevent their opening or physical access while pressure differential exists,

(ii) the need to contain hazardous substances and to mitigate the effects of any hazard related to their release,

(iii) the surface temperature of the boilers and pressure systems, and

(iv) the decomposition of unstable fluids; and

(c) be approved by an authorized inspector.

Loads and other factors

(4) The operator must ensure that boilers and pressure systems can withstand all combinations of loads, pressures, temperatures, fluids and substances to which they may be subjected during their design service life.

Materials used

(5) The operator must ensure that the materials used for the manufacture of boilers and pressure systems are compatible with their operating environment and are chemically resistant to the fluids they contain during their design service life.

Manufacturer's documents and records

(6) The operator must ensure that the following documents and records are obtained from the manufacturer of the boilers and pressure systems:

(a) documents demonstrating that manufacturing, testing and installation have been carried out in accordance with the design specifications provided for in a quality assurance program that is approved by an authorized inspector;

(b) records of the procedures that were followed in the welding, brazing and non-destructive examination of the boilers and pressure systems, including the results of the welder qualification tests specific to the welding and brazing procedures;

(c) documents evidencing the qualifications of persons involved in manufacturing, inspection and testing, including welders; and

(d) traceability records for the components of the boilers and pressure systems.

Construction, installation, commissioning, inspection and testing

(7) The operator must ensure, before a boiler or pressure system is put into operation, that it has been

(a) constructed, installed and commissioned by persons with the necessary experience, training, qualifications and competence to do so safely and in a manner that protects the environment; and
(b) subjected to any inspections by an authorized inspector and tests by or under the direction of an authorized inspector, including non-destructive examination and proof tests, that are necessary to ensure its integrity and compliance with design specifications.

Authorized inspector

(8) The operator must ensure that a boiler or pressure system is inspected by an authorized inspector and tested by or under the direction of an authorized inspector
(a) before the boiler or pressure system is put into operation following its installation;
(b) before the boiler or pressure system is put into operation following any modification or repair to it, including welding; and
(c) at any other interval as required by the standards on which the design of the boiler or pressure system is based.
Operating procedures

(9) The operator must ensure that operating procedures are developed for the boilers and pressure systems that inform users of operating hazards and indicate any special measures to be taken to reduce risks when the boilers and pressure systems are being used, maintained or repaired.

Conformity with procedures

(10) The operator must ensure that any boiler or pressure system is used, maintained and repaired in accordance with the operating procedures referred to in subsection (9).

Alteration of fitting

(11) It is prohibited for any person to alter, interfere with or render inoperative any boiler or pressure system fitting, except for the purpose of adjusting or testing the fitting.

Register

(12) The operator must keep a register of all boilers and pressure systems that includes the following documents and information in respect of each:
(a) accurate design calculations, technical drawings and design specifications, including evidence of the design approval by an authorized inspector;
(b) a list of the standards on which the design of the boiler or pressure system is based;
(c) the boiler or pressure system's operating limits, including its pressure and temperature ratings;
(d) all documents and records required from the manufacturer under subsection (6);

(e) in respect of each inspection and test referred to in subsection (7) or (8), a record created and signed by the authorized inspector who conducted the inspection that includes

(i) the date of the inspection or test,

(ii) information that identifies the boiler or pressure system that was inspected or tested, as well as its location,

(iii) the range of safe pressure and temperature at which the boiler or pressure system may be operated,

(iv) a declaration by the authorized inspector who conducted the inspection or who conducted or directed the test as to whether the boiler or pressure system meets the standards that were applied in its design and manufacture,

(v) a declaration by the authorized inspector who conducted the inspection or who conducted or directed the test stating that the boiler or pressure system is fit for the purposes for which it is to be used,

(vi) any recommendations regarding the need for modifications to the maintenance program established under section 159, and

(vii) any other observation relevant to safety; and

(f) a description of each repair or modification made to the boiler or pressure system.

Marking

(13) The operator must ensure that a boiler or pressure system is marked with any information that is necessary for its safe installation and operation, including an identifier that permits reference to the documents and records referred to in subsection (6) and the information referred to in paragraphs (12)(e) and (f).

Verification

(14) The operator must ensure that all operating procedures developed in accordance with subsection (9) and the register referred to in subsection (12) are periodically verified by the certifying authority.

Non-application

(15) This section does not apply to any of the following:

(a) a heating boiler that has a heating surface of 3 m^2 ***or less;***

(b) a pressure system that is installed for use at a pressure of one atmosphere of pressure or less;

(c) a pressure vessel that

(i) has a capacity of 40 L or less; or

(ii) has an internal diameter of

(A) 152 mm or less, or

(B) more than 152mm but not more than 610 mm if the pressure vessel is used for the storage of hot water or is connected to a water pumping system containing compressed air that serves as a cushion;

(d) a refrigeration plant that has a refrigeration capacity of 18 kW or less; or
(h) a domestic water and plumbing system.

General

- Refer to the definitions of "authorized inspector" and "pressure system" in section 1 and "process vessel" in section 97 of the *Framework Regulations*. A "process vessel" is considered to be a "pressure vessel" under the definition of pressure system if it is not excluded in the non-application requirement of subsection 135(15) of the *Framework Regulations*.
- With respect to subsections 135(6), (9) and (12) of the *Framework Regulations*, it is acceptable that documents and information may be contained in other areas of the management system as long as they are accessible to persons that require them. All components of boilers and pressure systems should have information available to demonstrate that they meet the regulations.
- Changes to equipment or the addition of equipment, whether it be permanent or temporary, may have an impact on the associated risk assessments that have been undertaken and compliance to these regulations. These changes should be assessed through a formal management of change process to determine if the existing measures implemented within this section will continue to be appropriate following a change.

Design, Construction and Installation

- With respect to section 107 and subsection 135(1) of the *Framework Regulations*, pressure and piping systems containing hydrocarbons or other hazardous substances should be designed with appropriate containment systems including bunding and drainage.
- With respect to subsections 135(1), (2), (3), (4) and (5) of the *Framework Regulations*, refer to the requirements and associated guidance for the use of non-combustible materials in the design of non-hydrocarbon piping systems in section 111 of the *Framework Regulations*.
- With respect to subsection 135(5) of the *Framework Regulations*, materials used in the manufacturing of pressure systems should be rated for the fluids they contain and if there is a risk, other measures should be taken to reduce the risk (e.g., chemical injection, increased inspection frequency).
- Guidance is provided in the following:
  - SOLAS and associated IMO resolutions or circulars in relation to pressure equipment for marine/utility systems and the MODU Code for drilling systems.
  - Flag state and classification society rules.
  - *ASME Boiler and Pressure Vessel Code (Sections I, II, IV, V, VII, VIII and IX).*
  - *CSA B51 Boiler, pressure vessel and pressure piping code.*
  - *ISO 28300 Petroleum, petrochemical, and natural gas industries – Venting of atmospheric and low-pressure storage tanks.*
  - *API Std 2000 Venting of Atmospheric and Low-pressure Storage Tanks.*
  - With respect to piping and fittings, refer to the following:
    - *ASME B31.3 Process Piping.*

        - *ISO 13703 Petroleum and Natural gas industries – Design and Installation of piping systems on offshore production platforms.*
    - With respect to pressure relieving devices, refer to the following:
        - *API Std 520 Sizing, Selection and Installation of Pressure-relieving Devices Part 1 – Sizing and Selection.*
        - *API Std 520 Sizing, Selection and Installation of Pressure-relieving Devices Part 2 – Installation.*
        - *API Std 526 Flanged Steel Pressure-relief Valves.*
        - *API Std 527 Seat Tightness of Pressure Relief valves.*
    - With respect to fired or unfired heat exchangers and heaters, refer to the following:
        - *API Std 660 Shell-and-tube Heat Exchangers.*
        - *API Std 661 Petroleum, Petrochemical, and Natural Gas Industries - Air-cooled Heat Exchangers and IOGP Specification S-710 Supplementary Specification to API Std 661 Air-Cooled Heat Exchanger.*
        - *API Std 662-1/ISO 15547-1 Plate Heat Exchangers for General Refinery Services - Part 1 - Plate-and-Frame Heat Exchangers.*
        - *API Std 663 Hairpin Type Heat Exchangers.*
        - *API Std 664 Spiral Plate Heat Exchangers.*
        - *API Std 668 Brazed Aluminum Plate-fin Heat Exchangers.*
    - With respect to inert gas generators and offloading and bulk transfer stations, refer to *API RP 2FPS Recommended Practice for Planning, Designing, and Constructing Floating Production Systems* and flag state and classification society rules.
    - With respect to cleaning/pigging equipment, consideration should also be given to the requirements of *CSA Z432: Safeguarding of Machinery* (makes reference to relevant ISO standards), which is referenced under Part 28 of the *OHS Regulations*.
- Specific attention should also be made regarding practices around shipping, handling and storage of PSVs and other valves, the management of interlocks on PSVs and the proper installation, use and inspection of leak detection pipes on PSVs designed with a bellow.

Inspection, Testing and Maintenance

- Refer to requirements and associated guidance for operations and maintenance of these systems under sections 153, 155, 156, 157 and 158 of the *Framework Regulations*.
- With respect to paragraph 135(8)(c) of the *Framework Regulations*, it is recognized that most design standards do not include inspection intervals. Operators should propose alternative standards such as those noted below, in determining appropriate inspection intervals.
- Guidance is provided in the following:
    - Flag state and classification society rules.
    - *API 510 Pressure Vessel Inspection Code: In-service Inspection, Rating, Repair and Alteration.*
    - *API 570 Piping Inspection Code: In-service Inspection, Repair and Alteration of Piping Systems.*
    - *API 579-1/ASME FFS-1 Fitness for Service.*
    - *API RP 572 Inspection Practices for Pressure Vessels.*

- *API RP 574 Inspection Practices for Piping System Components.*
  - *API Std 653 Tank Inspection, Repair, Alteration and Reconstruction.*
  - *ASME PCC-3 Inspection Planning Using Risk-Based Methods.*
- PSVs should be inspected, tested and maintained in accordance with *API RP 576 Inspection of Pressure-relieving Devices* with revealed and non-revealed failures noted on inspection records. Appropriate spares should be available onboard to conduct the testing and subsequent recertification of PSVs or there should be a program in place to swap out PSVs.
- *API RP 571 Damage Mechanisms Affecting Fixed Equipment in the Refining Industry* should be considered in conjunction with the standards listed above to determine causes of damage mechanisms and associated deterioration.
- *API RP 580 Elements of a Risk-Based Inspection Program* should also be considered once a baseline has been established from regular inspections, results and documented history.
- A re-assessment of inspection intervals should be performed after significant changes in process or following any significant deficiencies noted.
- Specific attention should also be made regarding practices around shipping, handling and storage of PSVs and other valves, the management of interlocks on PSVs and the proper installation and use of leak detection pipes on PSVs designed with a bellow.
- With respect to the qualification and certification of non-destructive testing persons, refer to the requirements and associated guidance for paragraph 157(1)(p) of the *OHS Regulations*.

Repairs

- Guidance is provided in the following:
  - *ASME PCC-2 Repair of Pressure Equipment and Piping.*
  - For temporary repairs, refer to the guidance provided in section 159 of the *Framework Regulations*.
  - In addition, for composite repairs to pipework, refer to *ISO 24817 Petroleum, petrochemical and natural gas industries - Composite repairs for pipework - Qualification and design, installation, testing and inspection*. NDE and inspections should be performed at appropriate intervals to verify remaining wall thickness, inspect defect(s), and verify internal corrosion or erosion effects to meet the requirements of sections 8.2, 8.4 and 8.5.3 of ISO 24817.

Section 136 - Mechanical Equipment

136 (1) An operator must ensure that any mechanical equipment on an installation
(a) is designed, selected, located, installed, commissioned, protected, operated, inspected and maintained in accordance with the measures referred to in clauses 9(2)(b)(v)(E) and 10(2)(b)(v)(E) that are described in the operator's safety plan and environmental protection plan, respectively; and
(b) can operate safely and reliably under all foreseeable operating conditions, taking into account the manufacturer's instructions.

Design

(2) Mechanical equipment must be designed to eliminate hazards to safety or the environment in the following scenarios or, if that is not possible, to mitigate the risks posed by those hazards:
(a) loss of containment of hazardous substances;
(b) overspeeding and loss of restraint of machinery components with high kinetic energy;
(c) extreme surface temperatures of the mechanical equipment;
(d) movement of mobile components of the mechanical equipment;
(e) loss of control and integrity of the mechanical equipment;
(f) ignition of potentially explosive atmospheres in hazardous areas from sparks, flames or excessive heat; and
(g) escalation of accidental events.

Controls and manual shut-off devices

(3) The operator must ensure that controls and manual shut-off devices for mechanical equipment are in a protected and readily accessible location that permits safe operation when an accidental event occurs that renders the equipment inaccessible.

Internal combustion engine - Operating instructions

(4) The operator must ensure that the basic operating instructions for an internal combustion engine provide details of stop, start and emergency procedures and are permanently attached to the engine.

Turbines and internal combustion engines

(5) The operator must ensure that turbines and internal combustion engines are
(a) equipped to prevent unintended ignition;
(b) installed so that
(i) their supply of combustion air is from a non-hazardous area, and
(ii) their exhaust is discharged to a non-hazardous area; and
(c) equipped with safety devices — including manual fuel shut-off devices and, unless it would increase safety or environment risks, automatic fuel shut-off devices — to prevent major damage from overspeeding, high exhaust temperature, high cooling water temperature, low lubricating oil pressure or other foreseeable hazards that could impair the safety of operations.

Exception

(6) Despite paragraph (5)(c), turbines and internal combustion engines that are critical to emergency response, including emergency generators and fire pumps, need only be equipped with safety devices to prevent major damage from overspeeding.

Operation of critical mechanical equipment

(7) The operator must ensure that mechanical equipment that is critical to the safety or propulsion of a floating platform will continue to operate safely and reliably at its full rated power under the static and dynamic angles of inclination that are specified in the rules of the classification society that issued the certificate of class required under section 140.

General

- Refer to the requirements and associated guidance for equipment and hazardous energy under Parts 18 and 27 of the *OHS Regulations*. In particular, pursuant to subsection 87(1) of the *OHS Regulations*, any activities carried out on equipment that poses a hazard to persons must be done in accordance with the manufacturer's instructions.
- Refer also to the requirements and associated guidance for physical and environmental conditions, risk assessments, controls and monitoring systems under sections 98, 104, 106, 107, 108, 110 and 169 of the *Framework Regulations*.
- With respect to subsection 136(2) of the *Framework Regulations*, mechanical equipment that vents to the atmosphere should be designed such that the amount of greenhouse gas emissions that can be released into the environment is minimized to as low as reasonably practicable.
- With respect to subsection 136(5) of the *Framework Regulations*, it is interpreted that manually-operated portable or temporary internal combustion engines used in internal non-hazardous areas need not be equipped with the safety devices required by this subsection of the regulation as long as they are not left unattended during their operation.
- If mechanical equipment is specified in a code or standard that has been adopted, the requirements of this section of the regulations must be considered.
- While several standards are noted below for various pieces of equipment not all standards are referenced. Equipment components such as flame arresters, spark arrestors, gears, lubrication systems, etc., should be designed, installed, inspected, maintained and tested to appropriate standards and consider manufacturer's instructions.
- All mechanical equipment must be protected from being a source of ignition if it is planned to be operated intentionally (or unintentionally) in a hazardous environment.
- Refer to the requirements and associated guidance for operations and maintenance under sections 153, 155, 156, 157 and 158 of the *Framework Regulations*.
- Changes to equipment or the addition of equipment, whether it be permanent or temporary, may have an impact on the associated risk assessments that have been undertaken and compliance to these regulations. These changes should be assessed through a formal management of change process to determine if the existing measures implemented within this section will continue to be appropriate following a change.
- If another installation, vessel or support craft is operating close to a drilling and production installation, a review should be undertaken of the mechanical equipment onboard to determine if the systems are adequately protected to prevent it from being a source of ignition.

Scope

Mechanical equipment is interpreted to include any equipment that contains rotating parts, reciprocating parts or other equipment with stored kinetic or potential energy as referenced in other sections of the *Framework Regulations* (e.g., any engine, pump, compressor, winch) or *OHS Regulations* (e.g., elevators), including temporary equipment. The list of mechanical equipment should include the following:

- Engines
- Turbines
- Generators and motors
- Pumps
- Compressors
- Fans
- Propulsion systems
- Mooring winches/windlasses
- Gears and gear trains
- Couplings
- Turrets (including swivels)

Mechanical equipment is also interpreted to include the following equipment noted in other sections of the regulations:

- For materials handling equipment, including drilling hoisting equipment and mobile equipment, refer to the requirements and associated guidance under section 137 of the *Framework Regulations*.
- For elevators and personnel lifts, refer to the requirements and associated guidance under Part 19 of the *OHS Regulations*.
- For mechanical shop equipment and handheld tools, refer to the requirements and associated guidance under Part 18 of the *OHS Regulations*.

General Standards

Overall guidance for all mechanical systems can be found in the following references:

- SOLAS, the MODU Code and associated IMO resolutions and circulars.
- Flag state and classification society rules.
- *ISO 13702 Petroleum and natural gas industries - Control and mitigation of fires and explosions on offshore production installations - Requirements and guidelines* contains guidance on internal combustion engines and turbines.
- *NORSOK S-001 Technical Safety* contains guidance on ignition source control.
- *API RP 14C Analysis, Design, Installation, and Testing of Safety Systems for Offshore Production Facilities* contains guidance on spark arrestors, flame arrestors, hot surface protection and hot equipment shielding for all permanent and temporary equipment.
- *CSA Z432 Safeguarding of Machinery* which is incorporated by reference in section 91 of the *OHS Regulations* contains requirements for the identification of all hazards, the assessment of risk and the identification of risk controls associated with machinery and equipment. It also makes reference to other international standards related to the design of equipment.
- *European Union Directive 2006/42/EC on Machinery* contains guidance for the identification of hazards, assessment of risk and identification of risk controls for machinery and equipment.
- *API RP 584 Integrity Operating Windows.*

- *API Std 670 Machinery Protection Systems.*
- *API RP 686 Machinery Installation and Installation Design.*
- *API RP 691 Risk-based Machinery Management.*
- *ISO 7825 Shipbuilding - Deck Machinery – General Requirements.*
- *ISO 80079-36 Explosives atmospheres – Part 36: Non-electrical equipment for explosive atmospheres – Basic method and requirements.*

Equipment Specific Standards

Guidance on individual pieces of equipment is provided in the standards below; however, it should be noted that adoption of these standards does not imply that additional features have been installed as per subsections 136(2) and (5) of the *Framework Regulations*. The following standards are noted:

- **Engines**
  - *NFPA 37 Standard for the Installation and Use of Stationary Combustion Engines and Gas Turbines.*
  - Refer to the requirements and associated guidance for electrical systems under sections 122 and 126 of the *Framework Regulations*.

- **Turbines**
  - *API Std 611 General-purpose steam turbines for Petroleum, Chemical, and Gas Industry Services.*
  - *API Std 612 Petroleum, Petrochemical and Natural Gas Industries - Steam Turbines-Special-purpose Applications.*
  - *API Std 616 Gas Turbines for the Petroleum, Chemical, and Gas Industry Services.*
  - *ISO 21789 Gas turbine applications—Safety.*
  - *NFPA 37 Standard for the Installation and Use of Stationary Combustion Engines and Gas Turbines.*
  - Refer to the requirements and associated guidance for electrical systems under sections 122 and 126 of the *Framework Regulations*.

- **Generators and Motors**
  Refer to the requirements and associated guidance under sections 122 and 126 of the *Framework Regulations*.

- **Pumps**
  - *API Std 610 Centrifugal Pumps for Petroleum, Petrochemical, and Natural Gas Industries* and *IOGP Specification S-615 Supplementary Specification to API Std 610 Centrifugal Pumps.*
  - *API Std 674 Positive Displacement Pumps – Reciprocating.*
  - *API Std 675 Positive Displacement Pumps-Controlled Volume for Petroleum, Chemical, and Gas Industry Services*.
  - *API Std 676 Positive Displacement Pumps-Rotary*.

- Refer to the requirements and associated guidance for fire pumps under section 134 of the *Framework Regulations*.
- Refer also to the requirements and associated guidance for pressure systems under section 135 of the *Framework Regulations*.

- **Compressors**
  - *API Std 617 Axial and Centrifugal Compressors and Expander-compressors.*
  - *API Std 618 Reciprocating Compressors for Petroleum, Chemical, and Gas Industry Services*.
  - *API Std 619/ISO 10440-1 Rotary-Type Positive-Displacement Compressors for Petroleum, Petrochemical, and Natural Gas Industries*.
  - *API Std 672 Packaged, Integrally Geared Centrifugal Air Compressors for Petroleum, Chemical, and Gas Industry Services* and *IOGP Specification S-612 Supplementary Specification to API Std 672 Packaged, Integrally Geared Centrifugal Air Compressors* (except for the addition to section 6.1.8.2).
  - *API Std 692 Dry Gas Sealing Systems for Axial, Centrifugal, and Rotary Screw Compressors and Expanders* (applies to compressors referred to in *API Std 617* and *API Std 619*).
  - Refer to the requirements for compressors under section 84 of the *Framework Regulations*.
  - Refer also to the requirements and associated guidance for pressure systems under section 135 of the *Framework Regulations*.

- **Fans**
  API Std 673 Centrifugal Fans for Petroleum, Chemical and Gas Industry Services.

- **Propulsion Systems**
  Refer to the requirements and associated guidance under sections 146 - 150 of the *Framework Regulations.*

- **Mooring Winches/Windlasses**
  Refer to the requirements and associated guidance under sections 135, 146, 147 and 148 of the *Framework Regulations*.

- **Gears and gear trains**
  - *API Std 613 Special Purpose Gear Units for Petroleum, Chemical and Gas Industry Services* and *IOGP Specification S-713 Supplementary Specification to ANSI/API Standard 613 Special Purpose Gear Units*.
  - *API Std 677 General-purpose, Extruder, and Epicyclic Gear Units for Petroleum, Chemical, and Gas Industry Services*.
  - Additional guidance is available from the American Gear Manufacturer’s Association.

- **Couplings**
  API Std 671 Special-purpose Couplings for Petroleum, Chemical, and Gas Industry Services.

- **Turrets (Swivel/Swivel Stacks)**
  - *API RP 2FPS Recommended Practice for Planning, Designing, and Constructing Floating Production Systems.*
  - Refer to guidance and additional requirements for turrets on floating platforms under section 105 of the *Framework Regulations.*

Section 137 - Materials Handling Equipment

137 (1) An operator must ensure that all materials handling equipment is
(a) to the extent feasible, designed and constructed to prevent the failure of any of its parts, taking into account the conditions under which it is to be operated;
(b) to the extent feasible, equipped with safety devices that will ensure that any failure of any of its parts does not result in a loss of control of the equipment or of its load or result in any other hazardous situation; and
(c) operated taking into account the manufacturer's instructions and industry standards and best practices.

Marking

(2) The operator must ensure that all materials handling equipment is marked with its rated capacity and in a manner that identifies its manufacturer and model and that permits reference to any information that is necessary to its safe operation, including information regarding its design, construction, inspection, testing, maintenance and repair.

Inspection and proof test

(3) The operator must ensure that materials handling equipment that is to be used on an installation is inspected and proof-tested by a competent third party in the following situations to determine the equipment's rated capacity:
(a) the equipment is to be used on the installation for the first time;
(b) repairs or modifications have been made to the equipment's load-bearing components;
(c) the equipment has been in contact with an electric arc or current; and
(d) there is any other reason to doubt that the rated capacity of the equipment that was most recently certified under subsection (5) or the limitations that were most recently indicated under that subsection continue to be accurate, including as a result of damage sustained by the equipment or modifications made to it.

Criteria for inspection and testing

(4) The operator must ensure that the inspection and proof-testing is done in accordance with criteria established by the manufacturer or applicable industry design and safety standards,

including with respect to the frequency at which the equipment must be inspected and proof-tested to ensure its continued safe operation.

Rated capacity

(5) Following the inspection and proof test, the competent third party must certify in writing the rated capacity of the materials handling equipment and must indicate in writing any limitations that must be imposed on its use having regard to physical and environmental conditions.

Emergency slewing and lowering

(6) The operator must ensure that a crane with slewing capability is capable of retaining its slewing and lowering capability in emergency situations.

Pedestal crane

(7) The operator must ensure that a pedestal crane meets the following requirements:
(a) it must be equipped with
(i) appropriate travel-limiting devices for its boom, hoist, blocks and slewing mechanism,
(ii) a load-measuring device that has been calibrated in accordance with the manufacturer's specifications or any calibration standard that is at least as rigorous as those specifications,
(iii) a device to indicate its boom extension or load radius, if its rated capacity is affected by the extension or radius,
(iv) a device to indicate its boom angle, if its rated capacity is affected by that angle,
(v) a device for accessing anemometer readings, if the load that it is able to safely handle or support is susceptible to being reduced by wind,
(vi) a gross overload protection system, if it is used to move persons or things to or from a floating platform or vessel, and
(vii) a safe load indicator system that is programmed for different operating modes and includes load and moment measuring devices; and
(b) a load chart that specifies the boom angle and the safe working load for each block and for each operating mode, as well as any limitations indicated under subsection (5), must be posted inside its control cab.

Crane hooks

(8) The operator must ensure that all crane hooks are equipped with spring-loaded latches or other equally effective means of preventing the load from falling off the hook under any operating conditions.

Landing or taking off

(9) When an aircraft is landing on or taking off from a landing area, it is prohibited to move a crane in the vicinity of the landing area and, if feasible, the person operating the crane must ensure that the crane's boom is stowed.

Lifting device certification

(10) The operator must ensure that any materials handling equipment that lifts over 10 tonnes is certified by the certifying authority.

- Refer to the requirements and associated guidance for physical and environmental conditions, design for intended use and location, risk assessments, passive fire protection, hazardous and non-hazardous areas, ventilation, ignition prevention, escape, electrical systems, control and monitoring systems, emergency electrical power, communication systems, general alarm systems, fire and gas detection systems, fire protection systems, pressure systems and mechanical equipment under sections 98, 104, 105, 106, 107, 108, 110, 112, 113, 114, 115, 118, 122, 123, 124, 125, 129, 130, 132, 133, 134, 135, 136 and 169 of the *Framework Regulation*s.
- Refer to the requirements and associated guidance for materials handling equipment under Part 24 of the *OHS Regulations*.
- Refer to requirements and associated guidance for operations and maintenance of these systems under sections 153, 154, 156, 157 and 158 of the *Framework Regulations*.
- Refer to the COP: *Atlantic Canada Offshore Petroleum Industry Safe Lifting Practice Respecting the Design, Operation and Maintenance of Materials Handling Equipment*.

Section 138 - Subsea Production Systems

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138 (1) An operator must ensure that a subsea production system is designed, constructed, installed, commissioned, operated, inspected, monitored, tested and maintained in accordance with the measures referred to in clauses 9(2)(b)(v)(F) and 10(2)(b)(v)(F) that are described in the operator's safety plan and environmental protection plan, respectively.

Design

(2) A subsea production system must be designed so that
(a) the system can avoid foreseeable hazards or revert to a safe state when hazards are imminent;
(b) the system supports and seals connections to the well, pipelines, other subsea production systems or other installations;
(c) in the event of a loss of control or communication, the system will revert to a safe state;

(d) the failure of a single component of the system cannot cause or contribute to a major accidental event;
(e) barrier elements in each conduit that carries fluids are reliable, have the necessary redundancy and are arranged to
(i) prevent uncontrolled flow of well fluids,
(ii) minimize the quantity of fluids released from the conduit in the event of unintended release, and
(iii) permit testing of the integrity of the barrier elements without increasing safety or environmental risks;
(f) subsea equipment can withstand or is protected from any load to which it may be subjected that would result in mechanical damage;
(g) production risers can withstand or are protected from all hazards and environmental loads to which they may be subjected, other than icebergs; and
(h) the blowout preventer is supported by the system during drilling and the tree and any workover or intervention pressure control equipment are supported by the system after completion.

Disconnectable riser

(3) The operator must ensure that a riser that is connected to a floating platform that has a disconnectable mooring system or dynamic positioning system is designed to be capable of safely detaching in any foreseeable physical and environmental conditions.

Riser disconnect

(4) The operator must ensure that, if risers are designed to disconnect in order to avoid foreseeable hazards, riser fluids may be safely displaced by water or isolated.

Riser integrity

(5) The operator must ensure that, if a riser is disconnected, its integrity is demonstrated through testing once it is reconnected and before it is brought back into service.

Control of subsea production system

(6) The operator must ensure that a subsea production system is controlled from only one location at any given time.

Failure modes and effects analysis

(7) The operator must ensure that any subsea production system is assessed through a failure modes and effects analysis.

General

- Refer to the definition of “flowline”, “subsea production system” and “production installation” in section 1 of the *Framework Regulations*.
- Refer to the requirements and associated guidance for physical and environmental conditions, risk assessments, electrical systems, control and monitoring systems, emergency shutdown systems, pressure systems, mechanical equipment, station-keeping systems, fail-safe SSVs and pipelines under sections 98, 104, 106, 107, 108, 110, 122, 123, 124, 125, 133, 135, 136, 146, 147, 148, 149, 150, 165, 168 and 169 of the *Framework Regulations*.
- Refer to requirements and associated guidance for operations and maintenance of these systems under sections 73, 153, 155, 156, 157 and 158 of the *Framework Regulations*.
- This section is interpreted to apply to the following:
    - All subsea production systems to or from the wellhead to the emergency shutdown valves that are located onboard the installation.
    - Pigging or well entry/intervention equipment that may be located topsides and associated subsea control and monitoring systems should also be included.
- This section does not apply to topsides production systems or pipelines, unless otherwise noted in guidance for those sections.
- While offshore loading systems or offloading systems are not considered part of the subsea production system, the referenced standards provided below provide guidance with respect to the design, operation and maintenance of these systems.
- With respect to subsection 138(1) of the *Framework Regulations*, the subsea production system should be designed such that the amount of control fluid or hydraulic fluid released into the environment during its normal functioning is minimized to as low as reasonably practicable.
- With respect to paragraph 138(2)(f) of the *Framework Regulations*, this should be interpreted to include dropped objects, trawling, anchor drags, collisions, icebergs, etc.

Standards

- Guidance is provided in the following:
    - Classification society rules respecting subsea production systems.
    - *ISO 13628-1 Petroleum and natural gas industries - Design and operation of subsea production systems - Part 1: General requirements and recommendations*. This includes references to the ISO 13628 series of standards and to other standards. *ISO 13628-15 Petroleum and natural gas industries - Design and operation of subsea production systems - Part 15: Subsea structures and manifolds* is not referenced in ISO 13628-1 and should also be considered.
    - *API RP 17A Design and Operation of Subsea Production Systems - General Requirements and Recommendations* which includes normative references to the API 17 series of standards.

Section 139 - Temporary or Portable Equipment

139 (1) An operator must ensure that any temporary or portable equipment used on an installation is fit for the purposes for which it is to be used.

Assessment of temporary or portable equipment

(2) Before any temporary or portable equipment is installed or brought into service on an installation, the operator must ensure that the equipment and its integration with other equipment and systems are assessed to determine their impact on safety-critical elements and on the risk assessment referred to in subsection 24(3).

Measures

(3) The operator must ensure that temporary or portable equipment is managed in accordance with the measures referred to in clauses 9(2)(b)(v)(G) and 10(2)(b)(v)(G) that are described in the operator's safety plan and environmental protection plan, respectively, and in a manner that does not compromise the target levels of safety set out in those plans.

Verification by certifying authority

(4) The operator must ensure that temporary or portable equipment that is a safety-critical element is, before being put into operation, verified by the certifying authority to confirm its suitability and safe placement and hook-up.

- With respect to subsection 139(2) and section 162 of the *Framework Regulations*, temporary and portable equipment should also be assessed against any of the assumptions or measures identified from risk assessments completed under sections 107 and 108 of the *Framework Regulations*. As such, the measures in place to reduce risk, including any standards that have been adopted, should be equivalent to that in place for permanent equipment. In addition, as equipment may pose an occupational health and safety hazard to persons or a hazard to the environment, it should also be assessed against the requirements of the *OHS Regulations* and section 39 of the *Framework Regulations*.
- With respect to subsection 139(4) of the *Framework Regulations*, refer to section 162 of the *Framework Regulations* regarding notification to the CA. The level of verification that the CA requires is dependent on the type of equipment, its intended location for use, the processes in place for managing the equipment and the risk.
- For the management of temporary or portable equipment, processes should include:
  - a definition of what comprises temporary or portable equipment;
  - requirements for design, selection, installation, placement, operation and maintenance of temporary or portable equipment;

- o requirements for completion of a management of change and the assessment of compliance with the measures in associated risk assessments;
  - o requirements for integration of temporary or portable equipment with permanent systems (e.g., emergency shutdown, fire and gas systems);
  - o requirements for when temporary or portable equipment should be removed and the associated timeframes for which temporary equipment is made into a permanent arrangement;
  - o requirements for inspection, testing and maintenance;
  - o requirements for maintaining a tracking system (e.g., temporary equipment register);
  - o clear statement of responsibilities and description of interfaces of the operator with other employers, providers of services, suppliers and the CA and integration of procedures, as applicable; and
  - o requirements for reinstatement to normal operations following removal of temporary or portable equipment.
- The operator should ensure that hazard analysis, documentation, control of spares, maintenance interfaces, training, competencies, etc., are all properly managed and processes are integrated with other employers, providers of services and suppliers, as applicable.
- With respect to the lifting and transporting of temporary or portable equipment, refer to guidance provided in the COP: *Atlantic Canada Offshore Petroleum Industry Safe Lifting Practice Respecting the Design, Operation and Maintenance of Materials Handling Equipment*.
- Additional guidance is provided in the following:
  - o *DNV-ST-E272 - 2.7-2 Equipment assemblies* applies to equipment assemblies (e.g., wire line, coiled tubing units) and offshore frames with equipment.
  - o *NORSOK Z-015 Temporary Equipment.*

PLATFORMS

Section 140 - Classification

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140 An operator must ensure that a floating platform holds a valid certificate of class issued by a classification society that corresponds to the authorized work or activity to be carried out from the floating platform.

General

- Refer to the definition of “classification society” in the *Framework Regulations*.
- The operator should be aware of the bounds of base class requirements and ensure that either additional “class notations” or equivalent measures are in place and appropriate for the activities that the installation is intended to perform.

Monohull Floating Platforms

With respect to installations that are monohull floating platforms (e.g., FPSOs), refer to the following:
- *DNV-RU-OU-0102 Floating production, storage and loading units*
- *LR Rules and Regulations for the Classification of Offshore Units*

Mobile Offshore Drilling Units

With respect to installations that are MODUs, including self-elevating platforms, refer to the following:
- *DNV-RU-OU-0101 Offshore drilling and support units*
- *DNV-RU-0104 Self-elevating units, including wind turbine installation units and liftboats*
- *LR Rules and Regulations for the Classification of Offshore Units*

Section 141 - Air Gap

141 An operator must ensure that a platform that is either founded on the seabed or column-stabilized has a sufficient air gap to operate safely under the maximum environmental load conditions to which it may be subjected.

- Refer to requirements and associated guidance for physical and environmental conditions, design for intended use and location and stability in sections 104, 105, 106 and 142 of the *Framework Regulations*.
- Operating with a negative air gap should be avoided.
- With respect to potential impact from horizontal wave loads specifically for column stabilized units, additional guidance is provided in the normative references contained in *DNV-OS-C103 Structural design of column stabilised units.*

Section 142 - Stability

142 (1) An operator must ensure that a floating platform, whether intact or in a damaged condition, is stable and can be operated safely, having regard to all motions and loads to which it may be subjected, including by
(a) determining the stability and motion response characteristics of the platform using analysis or model testing;
(b) determining the critical maximum loads and motions that the platform can withstand;
(c) ensuring that all equipment is fastened to prevent unintended movement; and
(d) monitoring and recording all loads that could affect the motions, stability or inclination of the platform.

Freeboard

(2) The operator must ensure that a floating platform has sufficient freeboard to operate safely under the maximum environmental load conditions to which it may be subjected.

Requirements - Code

(3) The operator must comply with the applicable provisions of the MODU Code and Part B of the IS Code concerning the stability and motion response of a floating platform, which are to be read as mandatory.

Deadweight survey

(4) If the weight of a floating platform or a self-elevating mobile offshore platform changes by more than 1% of the lightship weight, the operator must ensure that a deadweight survey is carried out at the earliest opportunity and an up-to-date value of the lightship centre of gravity is calculated.

- Refer to the definition of "floating platform" in section 1 of the *Framework Regulations*.
- Refer to requirements and associated guidance for physical and environmental conditions, design for intended use and location, classification, ballast and bilge systems and watertight integrity in sections 104, 105, 106, 140, 144 and 145 of the *Framework Regulations*.
- With respect to subsection 142(3) of the *Framework Regulations*, refer to the following:
  - As per applicable provisions of the respective codes, the MODU Code applies only to mobile offshore drilling units as stated within this code, whereas the IS Code applies to ships.
  - *IMO International Convention on Load lines* and *IMO International Convention for Safety of Life at Sea (SOLAS)* for general stability requirements.
  - MARPOL and associated IMO circulars and resolutions should be considered for specific requirements for intact and damage stability for oil tankers.
- Additional guidance is provided in the following:
  - *ISO 19901-6 Petroleum and natural gas industries – Specific Requirements for offshore structures – Part 6: Marine Operations.* This standard should also be considered for self-floating structures during transporting, upending and installation of these structures (e.g., GBS with or without topsides, self-floating steel structures, spars and TLPs) with respect to design of stability, ballast systems, navigation systems, control and indicating systems requirements.
  - *ISO 19904-1 Petroleum and natural gas industries — Floating offshore structures – Part 1: Ship-shaped, semi-submersible, spar and shallow-draught cylindrical structures.*
  - *ISO 19905-3 Petroleum and natural gas industries - Site-specific assessment of mobile offshore units.*

- *IMO Resolution MEPC.311(73) – Guidelines for the Application of MARPOL ANNEX I – Requirements to Floating Production, Storage and Offloading Facilities (FPSOs) and Floating Storage Units (FSUs).*
- Flag state and classification society rules, such as:
  - *DNV-OS-C301 – Stability and watertight integrity.*

Section 143 - Self-Elevating Mobile Offshore Platform

143 (1) An operator must, in relation to a self-elevating mobile offshore platform, ensure that a site-specific assessment is conducted of the condition of the seabed, including seabed restraint, to ensure that the platform is stable and can be operated safely.

Requirements

(2) The operator must ensure that a self-elevating mobile offshore platform meets the following requirements:
(a) it must be equipped with systems to actively monitor
(i) hull inclination,
(ii) leg penetration into the seabed,
(iii) loads on each of the platform's legs, and
(iv) rack phase differential, if applicable; and
(b) its jacking mechanisms must be designed so that the failure of a single component does not cause an uncontrolled descent of the platform.

Suspension of operations and well shut-in

(3) The operator must ensure that the works and activities on a self-elevating mobile offshore platform are suspended and that all wells associated with the platform are brought to a safe shut-in condition if
(a) hull inclination or the rack phase differential exceeds the allowable limits set out in the operations manual in accordance with paragraph 157(3)(b);
(b) unexplained changes occur in the loads on any of the platform's legs;
(c) leg penetration into the seabed increases; or
(d) any other event threatens the stability of the platform.

Corrective measures

(4) In the case of any of the situations referred to in subsection (3), the operator must ensure that the works and activities on the self-elevating mobile offshore platform remain suspended and that all wells associated with the platform remain in a safe shut-in condition until the cause of the situation has been investigated and corrective measures have been taken.

General

- Refer to requirements and associated guidance for physical and environmental conditions, design for intended use and location, risk assessments, transport and positioning, ignition prevention, electrical systems, control and monitoring systems, pressure systems, mechanical equipment and air gap in sections 98, 104, 105, 106, 107, 108, 110, 121, 122, 123, 124, 125, 135, 136, 141 and 169 of the *Framework Regulations*.
- Refer to requirements and associated guidance for operations and maintenance of these systems under sections 153, 155, 156, 157 and 158 of the *Framework Regulations*.
- Refer to the MODU Code, any associated IMO resolutions or circulars with respect to self-elevating installations.
- Refer to flag state and classification society rules.
- With respect to remote offshore locations with limitations on options for transportation, if sea ice or icebergs are present, if physical and environmental conditions have the potential to exceed the approved design or if the seabed is too hard to provide adequate overturning stability in the physical and environmental conditions that may be encountered, then an alternative type of installation should be considered.
- With respect to moves between different wells, separate procedures should be developed that consider weather forecasts, weather windows and differences between the two locations. Refer to the requirements and associated guidance under section 121 of the *Framework Regulations*.
- With respect to ice management procedures, additional consideration should be given to the time it will take to move off location (i.e., T-time) to another location that is safe from the threat of ice.

Standards

- Guidance on the inspection and maintenance of jacking systems is provided in the following:
  - *DNV-RP-0075 Inspection and maintenance of jacking systems*
  - *ABS Guide for Survey and Inspection of Jacking Systems*
- Further guidance is provided in *Guidelines for the Selection and Operation of Jack-ups in the Marine Renewable Energy Industry*. It should be noted that this recommended practice is not reflective of the legislative requirements and physical and environmental conditions experienced in the *Offshore Area*, so these aspects would require additional consideration.

Section 144 - Ballast and Bilge Systems

144 (1) An operator must ensure that a floating platform is equipped with reliable ballast and bilge systems with the necessary redundancy in their components to
(a) maintain necessary draught, stability and hull strength under all foreseeable operating conditions;
(b) return the floating platform to a safe condition from an unintended draught, trim or heel;

(c) prevent unintended transfer of fluid within the system;
(d) empty and fill all tanks that are a part of the system; and
(e) completely and rapidly empty watertight spaces.

Requirement - Code

(2) The operator must comply with the applicable provisions of the MODU Code concerning ballast and bilge systems, which are to be read as mandatory.

Secondary ballast control station

(3) In the case of a column-stabilized mobile offshore platform, the operator must ensure that it is equipped with a secondary ballast control station that is equipped with
(a) an effective means of communication with other spaces that contain equipment relating to the operation of the ballast system;
(b) a ballast pump control and status system;
(c) a ballast valve control and status system;
(d) a tank level indicating system;
(e) a permanently mounted ballast schematic diagram;
(f) heel and trim indicators;
(g) a draught-indicating system;
(h) a system to indicate the available power from the main and emergency electrical power supplies; and
(i) a ballast system hydraulic or pneumatic pressure indicating system.

Location — secondary ballast control station

(4) The operator must ensure that a secondary ballast control station is located above the waterline in the final condition of equilibrium after flooding if the floating platform is in a damaged condition.

Failures modes and effects analysis

(5) The operator must ensure that the ballast and bilge systems are assessed through a failure modes and effects analysis before any authorized work or activity is carried out from the floating platform.

- Refer to the definition of “floating platform” in section 1 of the *Framework Regulations*.
- Refer to requirements and associated guidance for physical and environmental conditions, risk assessments, electrical systems, control and monitoring systems, communication systems, pressure systems, mechanical equipment, classification, stability and watertight integrity in sections 98, 104, 106, 107, 108, 110, 122, 123, 124, 125, 129, 135, 136, 140, 142, 145 and 169 of the *Framework Regulations*.

- Refer to requirements and associated guidance for operations and maintenance of these systems under sections 153, 155, 156, 157 and 158 of the *Framework Regulations*.
- With respect to subsections 2(1) and 144(2) of the *Framework Regulations*, the applicable provisions for ballast and bilge systems as outlined in sections 4.9 and 4.10 of the MODU Code are mandatory for floating platforms that are mobile offshore drilling installations. There are certain provisions within these sections of the MODU Code that are only applicable to column-stabilized platforms.
- The standards referenced in section 142 of the *Framework Regulations* are also applicable in this section.
- With respect to subsection 144(2) of the *Framework Regulations*, refer also to guidance for ballast and bilge systems in the following:
  - *ISO 19904-1 Petroleum and natural gas industries — Floating offshore structures – Part 1: Ship-shaped, semi-submersible, spar and shallow-draught cylindrical structures*.
  - *ISO 19901-6 Petroleum and natural gas industries – Specific Requirements for offshore structures – Part 6: Marine Operations* should be considered specifically during all stages of marine operations. This also includes requirements for ballast systems on fixed installations that are being floated into position.
  - For FPSOs, refer to MARPOL and *IMO Resolution MEPC 139(53) Guidelines for the Application of the Revised MARPOL Annex I Requirements to Floating, Production, Storage and Offloading Facilities' (FPSOs) and Floating Storage Units (FSUs).*
- Manual soundings should be conducted periodically to verify the accuracy of electronic tank level soundings and to verify that there are no issues such as sediment buildup in the tanks. Any discrepancies should be rectified as soon as possible.

Section 145 - Watertight and Weathertight Integrity

145 (1) The operator must comply with the applicable provisions of the MODU Code and Part B of the IS Code concerning watertight and weathertight integrity and freeboard, which are to be read as mandatory.

Watertight subdivision

(2) The operator must ensure that the floating platform is designed with sufficient watertight subdivision to ensure the preservation of reserve buoyancy and damage stability under all foreseeable conditions.

Load line certificate

(3) The operator must ensure that a floating platform
(a) holds an International Load Line Certificate or an International Load Line Exemption Certificate issued by the government of the state whose flag the platform is entitled to fly, as required under Article 16 of the International Convention on Load Lines, 1966; and
(b) is marked in accordance with the certificate.

Watertight and weathertight appliances

(4) The operator must ensure that the arrangement and specification of watertight and weathertight appliances complies with the measures referred to in clause 9(2)(b)(v)(H) that are described in the operator's safety plan.

Water ingress

(5) The operator must ensure that a floating platform is designed with systems and equipment that provide for the operation, monitoring and indication — both locally and at the ballast control stations — of the opening and closing of watertight doors and hatches and for the detection and provision of alerts of any water ingress into watertight spaces that are not designed to accumulate liquid.

Port lights

(6) The operator must ensure that the columns of a column stabilized mobile offshore platform do not have port lights or similar openings.

General

- Refer to requirements and associated guidance for physical and environmental conditions, risk assessments, electrical systems, control and monitoring systems, pressure systems, mechanical equipment, classification and stability in sections 98, 104, 106, 107, 108, 110, 122, 123, 124, 125, 135, 136, 140, 142 and 169 of the *Framework Regulations*.
- Refer to requirements and associated guidance for operations and maintenance of these systems under sections 153, 155, 156, 157 and 158 of the *Framework Regulations*.
- Refer also to guidance provided in SOLAS and any associated IMO circulars or resolutions.
- Refer also to requirements of flag state and classification society rules.
- With respect to subsection 145(1) of the *Framework Regulations* and as per the applicable provisions of the respective codes, the MODU Code applies only to mobile offshore drilling units as stated within this code, whereas the IS Code applies to ships.
- With respect to subsection 145(5) of the *Framework Regulations*, this provision is interpreted to apply to watertight doors and hatches that are used by persons on a frequent basis. Watertight doors and hatches that are bolted (i.e., are not considered "operable") should be kept closed unless access is required for purposes of inspection and maintenance. In such cases, access should be managed under the platform's work permit system.

Remotely Operated Watertight Doors and Hatches

If the installation has remotely operated watertight doors or hatches:

- All persons should be briefed in their safe operation and hazards during their orientation.
- Doors and hatches should only be operated by persons that have been trained in how to operate them.
- Doors and hatches should be set to "local" operation except for emergencies, tests or drills, as required by SOLAS.
- Doors and hatches should be fitted with both local visual and audible alarms that will activate when they are being closed, either locally or remotely. Audible alarms should be louder than any machinery that might potentially be running in the area.
- Signs should be posted that state "Warning – Open Door Fully Before Passing Through. This Door May Close Automatically".

Section 146 - Station Keeping

146 An operator must ensure that a floating platform is equipped with a mooring system or a dynamic positioning system to ensure station-keeping of the platform within its operating limits.

Refer to the requirements and associated guidance in sections 147, 148, 149 and 150 of the *Framework Regulations*. For clarity, thruster-assisted mooring systems should be assessed against the requirements of sections 147 – 148 of the *Framework Regulations*.

Section 147 - Mooring System

147 (1) An operator must that a mooring system with which a floating platform is equipped is designed, on the basis of analysis and model testing, to ensure
(a) safety and the protection of the environment;
(b) the stability and serviceability of the floating platform;
(c) the integrity and serviceability of the mooring system components, including any related topside equipment;
(d) the integrity and serviceability of drilling risers, production risers, export risers or any other type of riser;
(e) the necessary redundancy of the mooring system components to enable the floating platform to maintain its position with the loss of a single component or, for a thruster-assisted mooring system, the loss of the most effective thruster or a single failure in the power or control system;
(f) for a thruster-assisted mooring system, the ability of the floating platform to withstand extreme meteorological conditions in the event of a power failure;
(g) the ability of the floating platform to move from its position to avoid accidental events that it is not designed to withstand; and

(h) safe access and safe clearances with respect to subsea and surface components of the installation, any nearby installations, support vessels and evacuation systems.

Excursion limits

(2) The operator must ensure that the excursion limits of a floating platform that is equipped with a mooring system are established on the basis of the analysis and model testing referred to in subsection (1).

Loss of station-keeping or failure

(3) The operator must ensure that the floating platform has systems and processes to continuously detect loss of station-keeping or the failure of any mooring system component.

Monitoring

(4) The operator must ensure that mooring line tensions or other indicators of the integrity of the mooring system are monitored and kept within the mooring system's operating limits.

Measures

(5) The operator must ensure that measures to ensure that the mooring system continues to perform in accordance with its design specifications are implemented, including
(a) the assessment of the system's condition, periodically and if it is damaged or if damage to it is suspected; and
(b) the making of arrangements for timely repair or replacement in the event of damage or deterioration.

General

- Refer to requirements and associated guidance for physical and environmental conditions, risk assessments, hazardous and non-hazardous areas, ignition prevention, electrical systems, control and monitoring systems, communication systems, pressure systems, mechanical equipment, subsea production systems, classification, stability, disconnectable mooring systems and drilling risers in sections 98, 104, 106, 107, 108, 110, 113, 115, 122, 123, 124, 125, 129, 135, 136, 138, 140, 142, 148, 164 and 169 of the *Framework Regulations*.
- Refer to requirements and associated guidance for operations and maintenance of these systems under sections 153, 155, 156, 157 and 158 of the *Framework Regulations*.
- With respect to subsection 147(3) of the *Framework Regulations*, this refers to the line tension monitoring system that is found on a moored drilling installation, to mooring chain transponder beacons on the mooring lines of an FPSO, or to an acceptable equivalent arrangement.

- With respect to paragraph 148(4)(a) of the *Framework Regulations*, floating platforms with a disconnectable mooring system must be self-propelled.
- Given the nature of local physical and environmental conditions, additional assessment may be required to address unique risks to the mooring system. In addition, mooring chains (for both permanent and mobile mooring systems) should be replaced when the residual strength falls below the minimum break strength used in the design, as corrosion/wear can happen in areas that does not result in equivalent strength reduction.
- Mooring systems should also be designed such that inspection of all components of the mooring system can be carried out.

Standards

Guidance is provided in the following:
- *ISO 19901-7 Petroleum and natural gas industries — Specific requirements for offshore structures — Part 7: Stationkeeping systems for floating offshore structures and mobile offshore units.* This standard also includes guidance for mooring winches/windlasses.
- *ISO 19904-1 Petroleum and natural gas industries - Floating offshore structures – Part 1: Ship-shaped, semi-submersible, spar and shallow-draught cylindrical structures.*
- *ISO 19906 Petroleum and natural gas industries — Arctic offshore structures*.
- SOLAS, MODU Code and associated IMO resolutions and circulars.
- Flag state and classification society rules. The mooring systems should also have class notation from a classification society or be demonstrated as equivalent.
- The inspection, repair and discard for chain, wire rope and mooring handling equipment should consider the following:
  - *API RP 2I In-service Inspection of Mooring Hardware for Floating Structures*
  - *API RP 2MIM Mooring Integrity Management*

Section 148 - Disconnectable Mooring System

148 (1) If the mooring system with which a floating platform is equipped is disconnectable, the operator must ensure that the system is designed to ensure that disconnection can be accomplished in a controlled manner without creating a risk of drift-off.

Safety plan

(2) The operator must ensure that the disconnectable mooring system is designed and maintained in accordance with the measures referred to in clause 9(2)(b)(vi)(D) that are described in the operator's safety plan.

Primary and backup systems

(3) The operator must ensure that the disconnectable mooring system includes a primary system and a backup system for disconnection, both of which can be operated locally or from a remote location.

Floating platform capacity

(4) The operator must ensure that a floating platform that is equipped with a disconnectable mooring system is capable of
(a) safely manoeuvering away under its own power; and
(b) maintaining a safe position and heading while disconnected.

Criteria and procedures for disconnection

(5) The operator must ensure that criteria and procedures for disconnection are developed for all credible disconnection scenarios, including procedures for monitoring environmental conditions and providing alerts for worsening conditions that may require disconnection.

Disconnection and reconnection

(6) The operator must ensure that the disconnectable mooring system
(a) is capable of carrying out a planned disconnection after allowing time for the depressurization and flushing of subsea flowlines;
(b) is capable of carrying out an emergency disconnection after allowing time to safely shut in wells and subsea equipment;
(c) allows for the reconnection to the floating platform of the system and the flowlines in an orderly sequence, in the physical and environmental conditions described in the operations manual under paragraph 157(2)(c); and
(d) allows for the resumption of production after the system and flowlines have been reconnected to the floating platform following a planned disconnection.

Periodic verification of disconnection capability

(7) The operator must periodically verify the disconnect capability of the disconnectable mooring system and must record the findings resulting from the verification.

Excursion limits exceeded

(8) The operator must ensure that the emergency disconnection referred to in paragraph (6)(b) is initiated if the floating platform exceeds the excursion limits established under subsection 147(2).

- Refer to the requirements and associated guidance under section 147 of the *Framework Regulations*.

- If shear links are planned to be used as one of the means of disconnection from the moorings on a moored column-stabilized installation, their location should be clearly marked and communicated to persons involved in the operation and maintenance of the mooring system to prevent unintentional disconnection.
- The emergency disconnection method referred to in paragraph 148(6)(b) of the *Framework Regulations,* should have the ability to be activated in the shortest time possible to account for situations when immediate move off the location is required (e.g., impending collision, shallow gas release, large subsea gas leak).
- With respect to subsection 148(7) of the *Framework Regulations*, the disconnectable mooring system should:
  - be tested and proven to be effective in the water depths in which it will be operating;
  - be tested periodically in accordance with ISO standards, without physical disconnection, to demonstrate its continued capability and the competence of persons expected to use it; and
  - be tested, without physical disconnection, as part of emergency response drills involving scenarios that could result in a disconnect such that persons expected to use it remain familiar with the procedures. With respect to moored column-stabilized installations, anchor quick release drills should be undertaken according to the COP TQOP.

Sections 149 - 150 - Dynamic Positioning System and Disconnect System

149 (1) An operator must ensure that the design of a dynamic positioning system with which a floating platform is equipped
(a) is based on numerical analysis and model testing to ensure that the floating platform's position reference and directional control can be maintained within specified tolerances that satisfy design operational requirements in relation to all functional and environmental loads to which the system may be subjected at the floating platform's intended location;
(b) is based on a failure modes and effects analysis to ensure the segregation and redundancy of safety-critical systems and their components as necessary to maintain the platform's position in the event that credible scenarios of equipment failure are realized;
(c) allows the dynamic positioning system to withstand the loss from fire or flooding of all its components situated in any one watertight compartment or fire subdivision of the floating platform; and
(d) includes systems to monitor the parameters of operability and integrity of the critical systems of the dynamic positioning system and to provide alerts for critical system faults.

Excursion limits

(2) The operator must ensure that the excursion limits of a floating platform that is equipped with a dynamic positioning system are established based on the numerical analysis and model testing referred to in paragraph (1)(a).

Disconnect system

150 (1) An operator must ensure that a floating platform that is equipped with a dynamic positioning system has a disconnect system that
(a) is capable of carrying out a planned disconnection of the floating platform from the seabed after allowing time to prepare the risers and subsea flowlines for the disconnection;
(b) is capable of carrying out an emergency disconnection after allowing time to safely shut in wells and subsea equipment; and
(c) allows for reconnection in an orderly sequence, in the physical and environmental conditions described in the operations manual under paragraph 157(2)(c).

Demonstration

(2) The operator must periodically demonstrate by means of a trial or performance test that the disconnect system meets the requirements under subsection (1).

Excursion limits exceeded

(3) The operator must ensure that the emergency disconnection referred to in paragraph (1)(b) is initiated if the floating platform exceeds the excursion limits established under subsection 149(2).

General

- Refer to requirements and associated guidance for physical and environmental conditions, risk assessments, electrical systems, control and monitoring systems, communication systems, pressure systems, mechanical equipment, subsea production systems, classification, stability and drilling risers in sections 98, 104, 106, 107, 108, 110, 122, 123, 124, 125, 129, 135, 136, 138, 140, 142, 164 and 169 of the *Framework Regulations*.
- Refer to requirements and associated guidance for operations and maintenance of these systems under sections 153, 155, 156, 157 and 158 of the *Framework Regulations*.
- With respect to paragraph 149(1)(b) of the *Framework Regulations*, refer to section B.3.2 of *ISO 31010 Risk management - Risk assessment techniques* and *IMCA M166 Code of Practice on Failure Modes and Effects Analysis (FMEA).* In addition to conducting a design verification, sea trials should be conducted to verify the FMEA and to demonstrate the ability of the system to maintain position and heading in the physical and environmental conditions experienced in this operating area. Equipment, operating limits and procedures may need to be adjusted as a result.
- With respect to paragraph 149(1)(c) of the *Framework Regulations*, the DP system should meet the requirements of IMO Equipment Class 3 or equivalent.
- With respect to section 150 of the *Framework Regulations*, the disconnect system should be:
    - tested periodically, without physical disconnection, to demonstrate its continued capability and the competence of persons expected to use it; and

  - tested, without physical disconnection, as part of emergency response drills involving scenarios that could result in a disconnect such that persons expected to use it remain familiar with the procedures.
- If DP operations are planned to be conducted in proximity to another installation, vessel (e.g., diving, construction) or support craft then appropriate risk assessments should be undertaken to identify all hazards (e.g., platform layout, location of surface or subsea assets (e.g., buoys, risers, mooring), position reference systems compatibility, range, limitations (e.g., interference, dip zones, antenna heights and beam widths)). Appropriate simultaneous operation procedures and Contingency Plans should be in place. Refer also to guidance provided in sections 11 of the *Framework Regulations*.

Standards

- Additional guidance is provided in the following:
  - *ISO 19901-7 Petroleum and natural gas industries — Specific requirements for offshore structures — Part 7: Stationkeeping systems for floating offshore structures and mobile offshore units.*
  - *ISO 19904-1 Floating offshore structures – Part 1: Ship-shaped, semi-submersible, spar and shallow-draught cylindrical structures.*
  - *ISO 19906 Petroleum and natural gas industries — Arctic offshore structures*.
  - IMCA publications related to DP systems.
  - SOLAS and associated IMO codes, resolutions and circulars.
  - Flag state and classification society rules. The DP systems should also have class notation or equivalent from the classification society or CA.

Section 151 - Decisions and Exemptions

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151 For any floating platform that is registered outside Canada, the operator must
(a) establish a list of all flag State administration decisions and exemptions that apply to the floating platform in relation to any standards adopted by the International Maritime Organization;
(b) conduct a risk assessment to identify measures to reduce the safety and environmental risks in relation to those decisions and exemptions to a level that is as low as reasonably practicable; and
(c) establish an action plan to implement the measures referred to in paragraph (b).

No guidance required at this time.

Section 152 – Gap Analysis – MODU Code

152 The operator must, every time the MODU Code is updated,
(a) undertake a gap analysis between the criteria in the updated version and the version that applies to the floating platform based on its date of construction;
(b) conduct a risk assessment in relation to any gaps identified; and
(c) ensure that mitigation measures are implemented, as necessary.

Certain sections of the MODU Code are incorporated by reference in sections 142, 144 and 145 of the *Framework Regulations*. If other sections of the MODU Code are adopted as part of the OA, operators should perform a similar review and advise the *Regulator* and the CA of any changes as a result of this review.

ASSET INTEGRITY

Section 153 - Requirements

153 An operator must ensure that all installations, including their systems and equipment, are inspected, monitored, tested, maintained and operated to
(a) ensure safety, the protection of the environment and the prevention of waste; and
(b) ensure that they continue to perform in accordance with their design specifications under the operating conditions and maximum loads to which they may be subjected.

No guidance required at this time.

Section 154 – Non-Destructive Examination

154 An operator must ensure that a non-destructive examination of the critical joints and structural parts of an installation is conducted at least once every five years or more often as required to ensure the continued safe operation of the installation.

“Critical joints and structural parts” is interpreted to be any component, the failure of which could cause or prevent a “major accidental event” as defined in section 1 of the *Framework Regulations*, or whose function it is to prevent or reduce the severity of such an event. Based on the risk assessments undertaken, critical joints and structural parts could potentially include the hull, cargo tanks, ballast tanks, primary structures, secondary structures, tertiary structures, equipment supports, decks, fire and blast rated divisions, load-carrying components of materials handling equipment, dropped object protection structures, and riser impact protection structures where linkage is identified to a "major accidental event". Refer to the requirements and associated guidance for risk assessments under sections 107 and 108 of the *Framework Regulations*. It is interpreted that "non-destructive examination" can include general visual inspections, close visual inspections, non-destructive examinations and condition monitoring as recommended, as long as the type of inspection is commensurate with the level of risk. Additional guidance is provided in *ISO 19901-9 Petroleum and natural gas industries – Specific requirements for offshore structures – Part 9: Structural Integrity Management* and classification society rules. With respect to the qualification and certification of non-destructive testing persons, refer to the requirements and associated guidance for paragraph 157(1)(p) of the *OHS Regulations*.

Section 155 - Corrosion Management

155 (1) An operator must ensure that if a safety or environmental hazard would result from the failure due to corrosion - including corrosion from exposure to a sour environment - of any equipment, including process vessels, or of any piping, valves, fittings and structural elements that are part of an installation, that corrosion is prevented and managed throughout the life cycle of the installation.

Corrosion management program

(2) The operator must develop a corrosion management program that sets out the measures that are necessary to prevent critical failures from corrosion-related degradation and to ensure the continued integrity of safety-critical elements.

Program requirements

(3) The program must
(a) identify all safety-critical elements that are susceptible to degradation by corrosion;
(b) provide for the analysis that is necessary to determine corrosion degradation mechanisms and the limits and failure modes of the safety-critical elements referred to in paragraph (a), taking into account the physical and environmental conditions and chemicals to which it is foreseeable that the safety-critical elements may be exposed;
(c) include measures to prevent corrosion, as far as is practicable, and to mitigate or protect against the effects of corrosion;
(d) provide for the inspection and monitoring of corrosion and of any corrosion protection and prevention systems;
(e) provide for the collection and analysis of baseline and continuous data to monitor corrosion;
(f) provide for the continuous assessment, based on the data and analysis referred to in paragraph (e), of the maintenance activities and schedules referred to in paragraph 159(2)(f) to determine whether those activities and schedules are adequate to ensure corrosion

management of safety-critical elements and provide for the modification of those activities and schedules, if necessary;
(g) provide for timely preventive maintenance of any corrosion protection and prevention systems; and
(h) provide for the timely inspection, monitoring and maintenance of safety-critical elements in accordance with the requirements of the maintenance program referred to in paragraphs 159(2)(e) and (f) and for any necessary repair before the limits established in paragraph (b) are reached.

Program implementation and update

(4) The operator must ensure that the program is implemented and periodically updated, taking into account the data and analysis referred to in paragraph (3)(e).

General

- Refer to the requirements and associated guidance for physical and environmental conditions, design for intended use and location, risk assessments, materials, asset integrity and maintenance programs in sections 104, 105, 106, 108, 110, 153 and 159 of the *Framework Regulations*. The *ISO 19900* series standards referenced in section 105 of the *Framework Regulations* also contain guidance for corrosion control.
- This section applies to all systems and equipment onboard an installation.

Corrosion Management Program

Corrosion management programs should address the following:
- Selected design and related structures of the installation.
- Materials used for construction.
- Compatibility of materials.
- Physical and environmental conditions.
- Chemical properties of fluids and seawater, as applicable.
- Corrosion protection methods including coatings, cathodic protection (active or passive), material corrosion allowance and corrosion monitoring.
- Use of inhibitors as a measure to prevent or mitigate the effects of corrosion.
- Corrosion under insulation.
- Inspection and maintenance.

For clarity, the full life cycle of a corrosion management program should include the decommissioning and removal phase.

Standards

Guidance is provided in the following:

- *ISO 21457 Petroleum, petrochemical and natural gas industries – Materials selection and corrosion control for oil and gas production systems*.
- *ANSI/NACE MR-0175/ISO 15156 Petroleum and natural gas industries – Materials for use in H_2S-containing environments in oil and gas production*.
- *ASTM D610-08/SSPC-VIS 3 Standard Practice for Evaluating Degree of Rusting on Painted Steel Surfaces.*
- Classification society rules (e.g., *DNV–RP-C302 – Risk based corrosion management*).

OPERATIONS AND MAINTENANCE

Section 156 - Limits and Requirements

156 An operator must operate an installation, including its systems and equipment, in accordance with any limitations that are set out in the certificate of fitness under subsection 28(3), with any requirements under this Part and with the operations manual referred to in section 157.

No guidance required at this time.

Section 157 - Operations Manual

157 (1) An operator must develop an operations manual in respect of each installation that sets out or incorporates by reference the following documents and information:
(a) a general description of the installation, including its particular characteristics;
(b) the chain of command and the roles, responsibilities and authorities of persons during normal operations of the installation and in emergency situations;
(c) a brief description of the systems and equipment on the installation, including flow sheets and instructions for the assembly, use and maintenance of the systems and equipment;
(d) the operating limits of the installation, including those of its systems and equipment;
(e) the physical and environmental conditions under which the installation and any pipeline can operate without compromising safety or the protection of the environment and the physical and environmental conditions that the installation and pipeline can withstand, taking into account the results of any analyses, tests, numerical modelling or investigations undertaken under subsection 105(2);
(f) the results of the risk and reliability analysis conducted for the purpose of subsection 108(1);
(g) a list of the procedures necessary to ensure the safe operation of the installation, including its systems and equipment, within the limits described in paragraph (d);

(h) a list of the accidental events that would require implementing the contingency plan referred to in section 11, any possible trigger for such events and the measures to be implemented to avoid their occurrence;

(i) a list of the procedures, practices, resources and monitoring measures set out in the contingency plan referred to in section 11;

(j) the criteria for each platform's minimum penetration into the seabed or for the maximum scour of the platform's foundation and an indication of the arrangement of the platform's anchoring system;

(k) a description of the characteristics of each platform's foundation and its penetration into the seabed or an indication of the arrangement of the platform's anchoring system, as well as a description of the measures to be implemented to monitor the integrity of the foundation or that of the mooring and anchoring systems;

(l) the criteria to identify meteorological and oceanographic conditions and phenomena that require subsea components and pipelines to be inspected;

(m) plans that show the arrangement of watertight and weathertight subdivisions;

(n) details of openings in watertight and weathertight subdivisions, including the location of vents, air pipes and all other means of water penetration, and the means of closure of the compartments, as well as the location of downflooding points;

(o) a plan that contains information concerning permissible deck loads, variable loading limits and preloading;

(p) details of all audible and visual signals and alarms used in the communication system referred to in section 129, the general alarm system referred to in section 130, the fire and gas detection system referred to in section 132 and the emergency shutdown system referred to in section 133, as well as details of any colour-coding systems used for the safety of persons on the installation;

(q) information on any corrosion protection and prevention systems, including their type and location, and any requirements for the safety and maintenance of those systems;

(r) technical drawings that show

> ***(i) the arrangement of any deck structure and of the equipment located on it, of all accommodations areas and temporary safe refuges and of any aircraft landing area, including its obstacle-free approach zone,***
>
> ***(ii) sufficient details to permit verification and management, if applicable, of the integrity of hulls, mooring components, primary and critical structures, foundation elements, jacking mechanisms, risers and conductors,***
>
> ***(iii) the arrangement of hazardous areas and of any equipment located in those areas, and***
>
> ***(iv) a fire control and evacuation plan, including***
>
> > ***(A) the location of escape routes, fixed fire suppression systems and life-saving appliances, and***
> >
> > ***(B) the arrangement of barriers that provide passive fire and blast protection and associated equipment, along with a description of those barriers and equipment;***

(s) the operating and maintenance requirements for all the life-saving appliances referred to in section 119;

(t) information identifying the aircraft that were used for the design of any aircraft landing area on the installation and the maximum weight, size and wheel centres of those aircraft;
(u) any special arrangements in place to facilitate the inspection and maintenance of the installation, including its systems and equipment, and the storage of any crude oil on the installation;
(v) special precautions to be taken or instructions to be followed when repairs or alterations to the installation, including its systems or equipment, are to be carried out;
(w) any special operational or emergency requirements and procedures with respect to any systems and equipment that are critical to safety, including the emergency shutdown system referred to in section 133;
(x) a description of the air gap or freeboard and of the means of ensuring that the requirements under section 141 and subsections 142(2) and 145(1) and (3), as the case may be, are met;
(y) the number of persons who can be accommodated on the installation during normal operations;
(z) a description of the main electrical power supply referred to in subsection 122(4) and the emergency electrical power supply referred to in section 126 and any limitations on their operation;
(z.1) the procedure for periodically documenting the results of all inspections, monitoring, testing and maintenance of the installation's integrity, including the format and presentation of that documentation; and
(z.2) the procedure for notifying the Chief Safety Officer and the certifying authority under subsections 162(1) and 170(1) and (2).

Additional information — floating platform

(2) In the case of a floating platform, the operations manual must also contain
(a) a description of the platform's station-keeping system and its capabilities, taking into account the platform's operating limits;
(b) all procedures for addressing the failure of any component of the station-keeping system that is critical to safety;
(c) if the station-keeping system is a mooring system, descriptions of the environmental loads that the moorings can sustain to keep the platform moored in place, the estimated holding power and capacity of the anchors in relation to the soil at the drill site or production site and the physical and environmental conditions in which reconnection of the platform is permitted;
(d) the procedures for addressing an excursion outside of the limits established in the context of the analysis and model testing under subsections 147(2) and 149(2);
(e) a description and the limitations of any onboard computer or computer-based control systems used in operations such as ballasting and dynamic positioning and in the platform's trim and stability calculations;
(f) instructions on how to assess the loading and ballast conditions of the platform to determine its stability and how to manage those conditions to maintain the platform's stability in accordance with the provisions referred to in subsection 142(3);
(g) data on the location, type and weights of permanent ballast installed on the platform;
(h) hydrostatic curves or equivalent data;

(i) a plan that shows the capacities and the centres of gravity of tanks and bulk material stowage compartments;
(j) tank-sounding tables or curves that show the capacities and the centres of gravity in graduated intervals and the free surface data for each tank;
(k) stability data that take into account the maximum height of the centre of gravity above the keel in relation to the draught curve or other parameters relevant to the stability of the platform;
(l) the results of any inclining test, or of any lightweight survey together with the inclining test results, and the updated location of the platform centre of gravity following a deadweight survey;
(m) examples of loading conditions for each mode of operation, together with the means to evaluate any other loading conditions;
(n) technical drawings that

> ***(i) show the arrangement and location of all openings that could affect the stability of the platform and their means of closure,***
> ***(ii) show the arrangement and operation of the ballast and bilge systems,***
> ***(iii) are accompanied by the operating instructions for the ballast and bilge systems, and***
> ***(iv) are sufficient in their scope and detail to ensure, in combination with the instructions referred to in subparagraph (iii), that***
>
> > ***(A) the necessary draught, stability and hull strength can be maintained under all foreseeable operating conditions, and***
> > ***(B) the floating platform can be returned to a safe condition from an unintended draught, trim or heel; and***

(o) a towing arrangement plan, if necessary, and the operating limits of the towing equipment's components.

Additional information — mobile offshore platform

(3) In the case of a self-elevating mobile offshore platform, the operations manual must also contain
(a) a description of any equipment for elevating and lowering the installation and details of any special types of joints and their purpose, including any operating or maintenance instructions for the equipment and joints; and
(b) the allowable limits for hull inclination and rack phase differential.

Up-to-date

(4) The operator must ensure that the operations manual is kept up-to-date.

Cross-References

With respect to the requirements of section 157 of the *Framework Regulations*, refer to the requirements and associated guidance provided within the *Framework Regulations* as noted :

Requirement	Cross-references
157(1)(c)	Facilities for inspection and maintenance in sections 110 and operations and maintenance in sections 73, 153, 159 and 161.
157(1)(e)	Physical and environmental conditions and design for intended use and location in sections 104, 105 and 106.
157(1)(l)	Guidance for special unscheduled inspections in section 159.
157(1)(q)	Corrosion management in section 155.
157(1)(r)(i)	Design for intended use and location in section 104.
157(1)(r)(iii)	Classification of hazardous and non-hazardous areas in section 113.
157(1)(r)(iv)(A)	Means of evacuation and escape, life-saving appliances and fire protection systems in sections 116, 118, 119 and 134.
157(1)(t)	Aircraft landing areas in section 174.
157(1)(t), (u), (z.1)	Facilities for inspection and maintenance and maintenance programs in sections 110 and 159.
157(2)(a),(b),(c),(d)	Station-keeping systems in section 146, mooring systems in sections 147 and 148 and DP systems in sections 149 and 150.
157(2)(e), (f), (g), (h), (i), (j), (k), (l), (m) and (n)	Stability and ballast and bilge systems in sections 142 and 144, watertight integrity in section 145 and DP in sections 149 and 150.
157(3)(a) and (b)	Design for intended use and location and self-elevating mobile offshore platforms in sections 105 and 143.

Note on Floating Platforms

With respect to floating platforms that are safety convention vessels, Chapter IX of SOLAS requires compliance to the ISM Code. The referenced MSC.1/Circ. 1253 references that all ships have a shipboard technical operating and maintenance manual which meets *IACS Recommendation No. 71 Guide for the Development of Shipboard Technical Manuals*. For MODUs, also refer to Chapter 14 of the MODU Code for additional details. The shipboard technical operating and maintenance manual required by SOLAS and the IMO MODU Code focus mostly on marine systems. The operator can use the flag state approved manual as part of the Operations Manual required under this section as long as it is supplemented with other procedures or information, as necessary, to address the other requirements of this section of the *Framework Regulations*. Subject to their approval, the flag state may permit the shipboard technical operating and maintenance manual to contain details on other systems.

Note on Fixed Installations

For fixed installations to which the above marine codes do not apply, the required information can be in several documents or procedures as long as its location is clearly communicated.

General Notes

- Regardless of whether the Operations Manual is a separate document or not, the required information should be properly documented and provided to end users in documents that are readily available, usable and updated. Information should not be embedded in original design documentation or other documentation not intended to be reviewed and updated.
- Clarity also needs to be provided to the CA as to which documents constitute the "Operations Manual" such that they can review and accept according to section 31 of the *Framework Regulations*.
- Any changes to details provided in the "Operations Manual" should go through the management of change process such that the CA is engaged in the review and acceptance and that the end users are made aware of any changes.
- If the "Operations Manual" is submitted as part of the Safety Plan and Environmental Protection Plan in an application for an OA, any changes should also be reviewed and accepted by the *Regulator*. Refer to the guidance and associated guidance under sections 9 and 10 of the *Framework Regulations*.

Section 158 - Programs

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158 (1) An operator must develop the following programs to ensure the continued integrity of an installation, including its systems and equipment, from the time the installation is commissioned until it is abandoned or removed from the offshore area:
(a) the maintenance program referred to in section 159;
(b) the preservation program referred to in section 160; and
(c) the weight control program referred to in section 161.

Program implementation and update

(2) The operator must ensure that the programs are implemented and periodically updated.

No guidance required at this time.

Section 159 – Maintenance Program

Maintenance program

159 (1) The maintenance program must set out the inspection, monitoring, testing and maintenance policies and procedures for the installation, including its systems and equipment, that are necessary to ensure safety, protect the environment and prevent waste.

Requirements

(2) The maintenance program must

(a) include the measures to ensure that the installation, including its systems and equipment, continues to perform in accordance with its design specifications;

(b) include the measures to ensure compliance with any inspection, monitoring, testing or maintenance requirements under this Part;

(c) include the performance standards developed by the operator for the installation, including for its systems and equipment;

(d) take into account the failure modes and mechanisms of safety-critical elements and the causes of their failure;

(e) include inspection and monitoring activities that occur at a frequency and in a manner to prevent, if practicable, the failures referred to in paragraph (d), or to mitigate the effects of those failures, and to ensure that safety-critical elements are repaired, replaced or modified without delay and in accordance with section 162; and

(f) include predictive and preventive maintenance activities and schedules for each safety-critical element that

> ***(i) are based on the performance standards referred to in paragraph (c),***
>
> ***(ii) take into account the manufacturer's recommendations and industry standards and best practices,***
>
> ***(iii) specify a minimum frequency for the comprehensive inspection of each safety-critical element, taking into account its condition and the conditions under which it is used,***
>
> ***(iv) for rotating equipment, provide for partial or complete dismantling and inspection at a frequency necessary to maintain the equipment in good condition and to ensure that the equipment's functionality, availability, reliability and performance are in accordance with its design specifications,***
>
> ***(v) provide for a periodic maintenance regime for any low running-hour equipment, such as emergency generators, essential generators and fire pumps, and***
>
> ***(vi) provide for the management of spare parts so that critical spare parts are available on the installation to ensure the continued functionality, availability, reliability and performance of each safety-critical element in accordance with its design specifications.***

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a. General

- Refer to the definition of "safety-critical elements" in section 1 of the *Framework Regulations*, which incorporates both safety and environmentally critical equipment.
- Unless otherwise limited to "safety-critical elements" within a particular requirement of the *Framework Regulations*, this section is intended to apply to all equipment, in general, that is required by these regulations.

- Pursuant to the *Accord Acts*[29], equipment, machines, devices, materials and other things critical to the health and safety of persons must be properly installed, stored and maintained, be safe for their intended use and be used as intended. Additional notes respecting requirements of the *OHS Regulations* are as follows:
    - Requirements for the competency, use, inspection, testing and maintenance of equipment, machines and devices are in Part 18 of the *OHS Regulations*. In particular, reference should be made to requirements in section 87 of the *OHS Regulations* respecting compliance to manufacturer's instructions, visual inspection before use and the requirements for thorough safety inspections (e.g., annual or as otherwise noted).
    - Any requirements respecting inspection, testing and maintenance of particular equipment as referenced in the *OHS Regulations* or a standard referenced within those regulations must be considered.
    - While this section of the *Framework Regulations* applies to all equipment onboard an installation, the maintenance program should also include any inspections, tests or maintenance related to OHS (e.g., noise surveys, water quality testing, air quality testing, PPE).
- Refer to the requirements and associated guidance provided for management systems in Part 3 of the *Framework Regulations* and refer to the requirements and associated guidance for risk assessments and other considerations in sections 107, 108, 110, 153, 154, 155, 158, 160 and 161 of the *Framework Regulations*.
- Inspection, testing and maintenance of particular equipment should also consider the following:
    - Any specified requirements within the *Framework Regulations* or a standard referenced within those regulations.
    - Any requirements referenced in a code or standard that has been adopted as part of the Certification Plan or as part of the application for an OA and any associated changes to those standards over time.
    - Any assumptions or measures from risk assessments, including:
        - With respect to functionality, availability (including assumed downtime), reliability (e.g., failure rate), survivability, etc.
        - With respect to the competency of persons performing those activities.
    - Any foreseen or other known failures of the particular equipment or system.
- The addition or removal of equipment, whether it be permanent or temporary, or a change to inspection, testing and maintenance, may have an impact on associated risk assessments and the compliance to regulatory requirements, manufacturer recommendations or any standards that have been adopted. These changes should be assessed through a formal management of change process. In addition, an assessment should also be undertaken if changes occur to codes or standards.
- The use of alternative technologies (e.g., remote pilot aircraft systems, remote operations) to conduct inspection, maintenance and testing activities instead of the methods described in standards, is acceptable if the method provides the same level of assurance as traditional methods. The use of alternative technologies should also be supported with risk assessments.

[29] C-NLAAIA 205.013(g) and 205.019(1)(m); CNSOPRAIA 210.013(g) and 210.019(1)(m)

New methods should be assessed in accordance with the requirements of section 103 of the *Framework Regulations*.

- With respect to subparagraph 159(2)(f)(vi) of the *Framework Regulations*, it is understood that not all critical spare parts for safety-critical elements can be kept onboard the installation due to physical space requirements, weight limitations or preservation requirements and some equipment may require the mobilization of specialist service providers to conduct repairs. In these circumstances, the time to repair should be documented and consider the impact to the risk. If target levels of safety are impacted, additional measures should be implemented to reduce risks.

b. Standards

Guidance on asset integrity and associated inspection, testing and maintenance programs is provided in the following:

- *Health and Safety Executive Key Programme 3 (KP3) – Asset Integrity Programme.*
- *Health and Safety Executive Key Programme 4 (KP4) – Ageing and Life Extension Programme.*
- *ISO 14224 Petroleum, petrochemical and natural gas industries - Collection and exchange of reliability and maintenance data for equipment.*
- *API 2FSIM Floating Systems Integrity Management.*
- *API RP 571 Damage Mechanisms Affecting Fixed Equipment in the Refining Industry.*
- *API RP 691 Risk-based Machinery Management*.
- *IEC 62402 Obsolescence Management.*
- Flag state and classification society rules.

c. Integrity Philosophies and Maintenance Strategies

General integrity philosophies and maintenance strategies should be developed for equipment systems that apply broadly to all equipment, including those that have been classified as a safety-critical element. This should include pressure systems, electrical systems, ventilation systems, mechanical systems, materials handling equipment, structural, etc.

d. Failure Modes and Mechanisms

With respect to paragraph 159(2)(d) of the *Framework Regulations,* failure modes and mechanisms of safety-critical elements should be assessed using formal techniques (e.g., FMEA, FMECA) and should include engagement with persons with experience in the design, operation and maintenance of the associated equipment. Guidance on these formal techniques is provided in the standards referenced under sections 108 of the *Framework Regulations*.

e. Performance Standards

With respect to paragraph 159(2)(c) of the *Framework Regulations*, the following guidance is provided:

- Performance standards should be in place for all safety-critical elements that have been identified in accordance with the risk assessments performed under section 108 of the *Framework Regulations* and the associated guidance.
- Performance standards or the associated maintenance program should normally address the following:

Objective	The purpose of the safety-critical element should be clearly stated and the standards that apply should be referenced. In addition to references to standards, it should include any associated requirements of flag state, classification society and the *Framework Regulations* and *OHS Regulations* (if applicable). It should also make reference to any relevant risk assessments that were undertaken.
Scope	The scope of the system should be described and the equipment covered should be specified. If a part of the system is not included, this should be clearly stated.
Functionality	The functions that must be performed by the safety-critical element should be described. The functions should be represented by either quantitative (i.e., something that is measurable such as rates, amounts, percentages) or qualitative measures.
Integrity	A description of what constitutes a failure or impairment of the safety--critical element should be included, along with associated implications and suggested measures to be taken (e.g., shutting down equipment, shutting down the system, restricting certain activities or shutting down certain operations). The measures should be effective, clearly described and commensurate with the level of risk. A variety of monitoring, inspection, testing and maintenance techniques should be used to ensure that any unforeseen failures or limitations can be detected and to provide confidence in the overall integrity of the element.
Availability	A description of the expected availability of a safety-critical element should be provided. For some elements, this can be obtained directly from quantitative risk assessments. The management system should be reflective of the maximum allowable time that the equipment can be taken out of service to conduct any required inspection, testing and maintenance. During assessments of the overall health of an element, the actual availability should be equal to or better than the expected availability.
Reliability	A description of the expected reliability of the safety-critical element should be provided. For some elements, this can be obtained directly

	from quantitative risk assessments. The performance standard should describe the percentage of time that an element will perform correctly (e.g., measured by the mean time between failures) and should establish the life expectancy of associated equipment, recognizing that some equipment may not be able to be designed to the same design life as the installation. Function testing should be set at a frequency to detect failures, and any detected failures should be rectified immediately. During assessments of the overall health of an element, actual reliability should be equal to or better than the expected reliability.
Dependability	A description of any issues with respect to dependability of the safety-critical element should be included. This refers to the ability of the element to continue to be supported and maintain its availability given the manufacturer, logistical and maintenance resources. Any equipment that may fail, or that requires material availability or support from the manufacturer should be clearly identified and monitored to ensure the continued availability of an element (i.e., to prevent obsolescence). Additional measures should also be identified to ensure that support or spare parts are available, when required (e.g., contracts, spares).
Survivability	A description of the measures taken to ensure a safety-critical element continues to operate during a major accidental event (e.g., fire, explosion), if required. Any additional measures that may need to be implemented should be described or referenced.
Interdependency	A description of any direct or indirect dependency on other systems should be included. This refers to the dependency of the safety-critical element on other systems or elements, which may impact its overall function. In addition, the impact(s) of the impairment of interdependent systems or elements should be included along with any associated measures.

- **Assurance** - Performance standards should include a direct link to the assurance activities that ensure that the above objectives are achieved. Assurance activities should include reference to specific inspection, testing and maintenance activities, routine inspection checks, review of recorded data, etc. Any activity completed should be reported and records should be maintained.

- **Verification -** Performance standards should also be verified routinely to ensure that they achieve the established objectives and that assurance activities are effective. Verification should be supplemented with objective evidence via review of reports, observation of inspection, testing and maintenance activities, and assessment of the condition and operation of the element. The operator should also assess the knowledge of persons completing assurance activities and the adequacy of operating and maintenance procedures for these elements to identify weaknesses or potential improvements. This verification should be conducted under the monitoring, compliance and continual improvement processes of the operator's management system and should be separate from the verification activity performed by the CA as part of its Scope of Work.

- Guidance on performance standards is provided in the following:
  - *ISO 17776 Petroleum and natural gas industries – Offshore production installations – Major accident hazard management during the design of new installations*.
  - *ISO 13702 Petroleum and natural gas industries - Control and mitigation of fires and explosions on offshore production installations - Requirements and guidelines* contains guidance on performance standards for safety-critical elements in relation to fires and explosions and guidance for typical inspection and testing frequencies of related equipment.
  - *NOPSEMA Guidance Note GN 0271 Control measures and performance standards.*
  - *NORSOK S-001 Technical Safety* contains guidance on performance requirements and performance standards.
  - The Step Change in Safety website also has guidance on asset integrity and major accident hazards, including performance standards.
  - Classification society rules in relation to performance standards and verification schemes.
  - Reference should also be made to ISO standards referenced in other sections of this Guideline, as some of these standards contain guidance on functional requirements and performance standards that should be considered (e.g., ISO 15138 for ventilation systems).

f. Maintenance Procedures

With respect to paragraphs 41(b) and (i) of the *Framework Regulations*, as working on equipment can result in fatalities, injuries or incidents, clear and concise instructions for performing inspection, testing or maintenance should be in place to assist in the prevention of incidents and to support consistency, effectiveness and efficiency in carrying out associated work activities. These instructions should either be stated directly in the maintenance routines or documented in separate procedures. Even though direct supervision may be provided when providers of service (e.g., inspection companies, manufacturer representatives) are onboard, they may not be knowledgeable of the procedures, hazards or equipment on the particular installation, so these instructions are of value to any person required to perform these activities.

g. Special Inspection, Testing or Maintenance

Although a planned maintenance program is in place, special inspection, testing or maintenance may need to be undertaken to rectify any issues. This should be conducted for events such as:

- Following direct exposure to a physical and environmental condition in excess of design of the installation or its associated equipment (e.g., storms, rogue waves, earthquakes, hurricanes, temperature, lightning).
- Following operations that may have caused an exceedance of design operating limits (e.g., overload of lifting equipment, operating above design pressures, collision, station keeping excursion limits, rig moves).
- Following an incident (e.g., fire, exposure to hazardous substance such as H_2S, dropped objects) which may have impaired or degraded the design rating of equipment.
- Following a notice being issued by the original equipment manufacturer regarding the equipment, or following failure of similar equipment in another application.
- Following a change in ownership of the installation that impacts staff or procedures applied onboard.
- Following a change in standards governing equipment or systems that may have an impact on the integrity or safety of those systems.
- Before return to normal operations following an extended shutdown (e.g., warm stacking, cold stacking or not being in operation for several months).

With respect to exposure to physical and environmental conditions or certain operations, this should include an inspection of any equipment that may become damaged or dislodged during the event such as gratings, supports, guardrails, etc.

h. Reporting of Damages and Impairments

- Any damages or impairments to safety-critical elements or equipment required by the *Framework Regulations* should be noted in daily reports, along with status. Refer to the requirements and associated guidance in section 197 of the *Framework Regulations*.
- In addition, refer to the requirements and associated guidance for reporting deterioration, damages and impairments to the *Regulator* and CA, if applicable, under sections 162, 170 and 179 of the *Framework Regulations*.

i. Reporting and Assessment of Critical Failures

All critical failures to critical safety devices (e.g., valves, detectors) revealed during planned testing or from an unplanned activation on demand should be included in periodic reports on the integrity of the installation. This data should be used to validate the reliability of equipment forming a part of a safety-critical element against assumptions made in associated risk assessments. Systems unable to meet performance criteria should be improved or maintenance routines modified as a result of the assessment. Refer to additional guidance found in standards that are referenced for performance standards. Reports on the integrity of the installation should be submitted to the *Regulator* annually as part of the annual safety report and environmental reports referred to in sections 182, 200 and 201 of the *Framework Regulations*.

j. Temporary Repairs

Any temporary repairs to equipment that is either a safety-critical element or required by the *Framework Regulations* or *OHS Regulations* should meet all requirements of its design and any requirement in an associated performance standard, before it can be considered an appropriate replacement.

With respect to temporary repairs to structural components and other types of temporary repairs (e.g., repairs to piping systems), the following should be considered:

- All temporary repairs should be maintained on a tracking register and remain classified as temporary until permanent repairs are made to ensure that proper inspections are being routinely completed.
- With respect to temporary repairs involving composite material:
  - Engineered wraps such as Technowrap 2K are an accepted approach for temporary repairs; however, non-engineered wraps such as Technowrap Core should be limited in use and based on type of service, associated risk and duration. As an example, one exception would be the application of a wrap on a pipe that has a wall thickness in excess of its minimum thickness but has degraded coatings – in this instance the wrap may prevent further degradation.
  - Fire performance risk assessments should be completed and the repair locations should meet the pre-repair substrate's fire requirements.
  - NDE and inspections should be performed at appropriate intervals to verify remaining thickness, inspect defect(s), and verify internal corrosion or erosion effects.
  - Composite repairs proposed to be operated past their design life should be re-evaluated and modifications conducted, if required.
  - Additional guidance is provided in *DNV-ST-C501 Composite Components.*
- With respect to temporary repairs to pipework, refer also to the additional guidance provided for section 135 of the *Framework Regulations*.

k. Asset Life Extension

In NL, refer to the *Asset Design Life Extension Program Guideline for Offshore Canada-Newfoundland and Labrador* for the extension of the operational life of an asset beyond its originally-defined design life.

l. Decommissioning and Abandonment

Before decommissioning and abandonment, an assessment of all equipment and structures must be undertaken to determine the safest and most environmentally responsible methods for decommissioning, removing or abandoning the installation. The assessment should consider whether the equipment and structure can be used beyond its operating life up to its eventual removal or abandonment. Guidance on decommissioning and abandonment plans is provided in section 15 of the *Framework Regulations*.

Section 160 – Preservation Program

160 (1) The preservation program must set out the measures that are necessary to ensure the integrity of equipment that is taken out of service and stored for future use.

Periodic inspection

(2) The program must provide for the periodic inspection of the stored equipment to verify its integrity and ensure that it is fit for the purposes for which it is to be used if it is brought into service.

Refer to the requirements and associated guidance in section 159 of the *Framework Regulations*.

Section 161 – Weight Control Program

161 The weight control program must set out the measures that are necessary to ensure that the weight and centre of gravity of each installation are kept safely within the installation's operating limits.

Guidance on weight control programs is provided in "Annex G - Requirements for weight control during operations" in *ISO 19901-5 Petroleum and natural gas industries - Specific requirements for offshore structures - Part 5: Weight management*, in the associated ISO 19900 series of standards. For MODUs, also refer to the MODU Code. Refer also to the requirements and associated guidance in section 159 of the *Framework Regulations* and the requirements and associated guidance for engagement of the CA under section 28 of the *Framework Regulations.*

Section 162 – Safety-Critical Element - Repair, Replacement or Modification

162 (1) The holder of a certificate of fitness must ensure that the certifying authority and the Chief Safety Officer are notified before a safety-critical element is repaired, replaced or modified and before any equipment that would change the design, performance or integrity of a safety-critical element is brought onboard the installation.

Approval before repair or modification

(2) The holder of a certificate of fitness must ensure that the approval of the certifying authority is obtained before a safety-critical element is repaired or modified.

Verification

(3) The holder of a certificate of fitness must ensure that a safety-critical element that has been repaired or modified is not put into operation until the certifying authority has verified it and
(a) confirmed that it is fit for the purposes for which it is to be used, can be operated safely without posing a threat to persons or the environment and meets the requirements of these Regulations; and
(b) imposed any limitation on the operation of the installation that is necessary to ensure that the installation meets the requirements referred to in paragraph 28(1)(b).

Emergency repair or modification

(4) In an emergency, subsections (2) and (3) do not apply if the installation manager considers that the delay required to comply with the requirements under those subsections endangers persons on the installation or the environment.

Verification after emergency

(5) A safety-critical element that is repaired or modified in an emergency must be verified by the certifying authority in accordance with subsection (3) as soon as the circumstances permit.

Non-application

(6) This section does not apply in the case of an adjustment made to or the testing of a boiler or pressure system fitting.

- Refer to the definition of "safety-critical element" in the *Framework Regulations*.
- Refer also to requirements and associated guidance for notice of deterioration in section 170 of the *Framework Regulations*.
- Refer to the requirements and associated guidance under section 179 of the *Framework Regulations* for reportable incidents, which includes reporting of impairments to safety-critical elements. With respect to repairs, the time to repair should be included in the associated written notification report submitted to the *Regulator*. Status updates on repairs, replacements or modifications, which have been reported as impairments, should also be noted in daily reports provided in accordance with section 197 of the *Framework Regulations*.
- With respect to subsection 162(1) of the *Framework Regulations:*
    - With respect to replacements:
        - This is not interpreted to include normal planned maintenance or routine replacement or refurbishment of equipment with equipment that is like-for-like.
        - If the manufacturer of the equipment is no longer in operation or the equipment is obsolete, the operators should assess the planned replacement against the certification, specifications and criteria for the previous equipment. Any deviations to

the certification, specifications and criteria requires notification to the *Regulator* and the CA.

- Bringing onboard any equipment that may change the design, performance or integrity of safety-critical elements, whether it is temporary or permanent, should be conducted in accordance with established management of change processes. Refer also to the requirements and associated guidance under section 139 of the *Framework Regulations.* In these cases, and in accordance with section 139 of the *Framework Regulations,* the operator should be engaged in the review to ensure that it does not impact the risk assessments undertaken and the associated measures.
- Any modifications that affect the Safety Plan, Environmental Protection Plan or Contingency Plan should be submitted for review in accordance with subsection 50(2) of the *Framework Regulations*. Modifications may involve further review or witness testing by the *Regulator,* CA or both. Engagement should occur before physical changes are made.

WELLS

Section 163 - Drilling Fluid Systems

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163 An operator must ensure that
(a) the drilling fluid system and associated monitoring equipment provide an effective barrier against formation pressure, ensure safe well operations, prevent pollution and allow for well evaluation;
(b) the indicators and alarms associated with the monitoring equipment are strategically located on the drilling rig to alert persons on it; and
(c) dedicated personnel provide continuous monitoring, using independent monitoring systems, of parameters that are critical to safe well operations or to the detection of a gain or loss of drilling fluid while the installation is connected to the well and is taking fluid returns.

General

- Refer to the requirements and associated guidance for well control (including the drilling fluid), physical and environmental conditions, risk assessments, hazardous and non-hazardous areas, ventilation, ignition prevention, electrical systems, control and monitoring systems, pressure systems, mechanical equipment and drilling risers in sections 68, 98, 104, 106, 107, 108, 110, 113, 114, 115, 122, 123, 124, 125, 135, 136, 164 and 169 of the *Framework Regulations*.
- For the discharge of drilling fluids into the environment, refer to sections 10 and 45 of the *Framework Regulations*.
- Refer to requirements and associated guidance for operations and maintenance of these systems under sections 73, 153, 155, 156, 157 and 158 of the *Framework Regulations*.

Drilling Fluid System

The following standards should be referred to for the design, installation, operations and maintenance of the equipment associated with drilling fluid systems, including the high pressure mud system, low pressure mud system, bulk system, cement system, mud conditioning system, degassing system, cuttings cleaning and associated monitoring systems:

- *NORSOK D-001 Drilling Facilities.*
- *NORSOK D-010 Well integrity in drilling and well operations.*
- *API RP 13C Drilling-fluid Processing Systems Evaluation.*
- Classification society rules related to drilling fluid systems and associated monitoring system.
- The design and use of mud gas separators atmospheric degasser should also consider the technical specifications and recommendations in section 1.7 of *Energy Safety Canada Industry Recommended Practice Volume 1 - Critical Sour Drilling*.
- In addition to NORSOK D-001, API RP 13C and classification society rules, the following should be considered:
  - Continuous monitoring of drilling fluid returns including automatic detection and visible and audible alarms in the event of any increase in gas levels. Continuous monitoring should be provided for in at least two locations and should include at the driller's station and from the mudlogging unit.
  - Measuring and recording of mud gas readings including the total hydrocarbon gas content and the chromatographic breakdown (e.g., relative amounts of methane, ethane, propane, butane).
  - Monitoring and alarms for the presence of H_2S 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, choke manifold and moon pool.

Competency

Guidance on competence of persons is provided in *API RP 13L Recommended Practice for Training and Qualification of Drilling Fluid Technologists.*

Section 164 - Drilling Riser

164 (1) An operator must ensure that every drilling riser is, throughout the duration of a well operation, capable of
(a) providing 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 maximum loads to which it may be subjected; and
(e) permitting the drilling fluid to be returned to the installation.

Drilling riser support

(2) The operator must ensure that every drilling riser is supported in a manner that effectively compensates for any loads caused by the motion of the installation, the drilling fluid or the water column.

Drilling riser analysis

(3) The operator must ensure that a drilling riser analysis and, in the case of a floating platform that uses a dynamic positioning system, a weak-point analysis of the drilling riser are conducted and that the certifying authority in relation to the installation approves those analyses.

General

- Refer to the requirements and associated guidance for well control, physical and environmental conditions, risk assessments, electrical systems, control and monitoring systems, pressure systems, mechanical equipment, materials handling equipment, stability and station-keeping systems under sections 68, 98, 104, 106, 107, 108, 110, 122, 123, 124, 125, 135, 136, 137, 142, 143, 146, 147, 148, 149, 150 and 169 of the *Framework Regulations*.
- Refer to requirements and associated guidance for operations and maintenance of these systems under sections 73, 153, 156, 157 and 158 of the *Framework Regulations*.
- The operator should ensure that high pressure riser systems are designed and operated such that:
  - they can withstand all environmental loads and any pressure or tension loads that could be expected;
  - the installation is not compromised by any forces applied to or by the riser; and
  - running and retrieving the riser is performed in accordance with operational limits and Contingency Plans are in place in the event the system fails or the limits are exceeded.

Riser Analysis

A site-specific dynamic riser response analysis, as discussed in *API RP 16Q Design, Selection, Operation and Maintenance of Marine Drilling Riser* Systems, should be undertaken based on the water depth, current profiles, expected drilling fluid densities, sea states, vessel motions, heave compensation equipment, 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 expected 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 physical and environmental conditions and drilling fluid densities expected.
- Establishing the operating envelope for the drilling riser 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.
- Determining the safe limits to prevent damage or failure during:
  - deployment and retrieval;
  - transitioning from connected to hang-off; and
  - hang-off and survival.
- Determining the inspection and testing criteria based on the physical and environmental conditions it is expected to be operated in and the associated water depths.

In addition:

- The dynamic riser response analysis should be performed with the best available data for the planned well location (e.g., physical and environmental condition data, current profiles, rig characteristics).
- The results of the riser analysis, particularly the operating envelope, buoyancy requirements, top tension requirements and operating limits should be provided to all persons required to have this information.

Anti-Recoil System

An anti-recoil system should be installed on the drilling riser tensioning system to prevent damage to the riser during emergency disconnection under high tension.

Slip Joint

The telescopic joint (slip joint) should be equipped with at least a double element packing unit so that in the event one of the packing elements fails, the other elements can be engaged to minimize the discharge of contents (e.g., drilling fluid) to the sea. Secondary and tertiary slip joint elements should be fitted in such a way that they will engage automatically in the event of failure of the primary element. Any proposed use of a single element slip joint packing unit would not be considered good practice given the physical and environmental conditions and should be discussed with the *Regulator*.

Riser Flex Joints

The following information should be available on 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.
- Evidence that the flex joint is at most five years old, unless documentation of a full tear down and inspection of the flex joint, according to manufacturer’s recommended practices, is available.

Operating Limits

- Safe limits for preventing damage or failure during deployment and retrieval, transitioning from connected to hang-off and from hang-off to survival should be determined and made available to all persons required to have this information.
- The operating envelope for the drilling riser should include installation offset or ball/flex joint angles, motions of the installation, 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.

Standards

Guidance is provided in the following:

- *NORSOK D-010 Well integrity in drilling and well operations.*
- *API Spec 16F Specification for Marine Drilling Riser Equipment.*
- *API RP 16Q Design, Selection, Operation and Maintenance of Marine Drilling Riser Systems*
- *ISO 19905-3 Petroleum and natural gas industries — Site-specific assessment of mobile offshore units.*
- Classification society rules with respect to drilling risers (e.g., *DNV-ST-F201 Riser Systems, DNV-OS-E101 Drilling Facilities*).

Section 165 - Fail-Safe Subsurface Safety Valves

165 (1) An operator must ensure that a completed development well is equipped with a fail-safe subsurface safety valve that
(a) can be operated from the surface; and
(b) if the well is located where permafrost is present in unconsolidated sediments, is installed in the production tubing below the base of the permafrost.

Additional valve

(2) The operator must ensure that a completed development well on a fixed platform that has gas-lift, injection or production capabilities in the A-annulus is equipped with an additional fail-safe safety valve on the A-annulus.

Requirements

(3) The operator must ensure that all fail-safe safety valves are designed, installed, tested, maintained and operated to prevent uncontrolled well flow when they are activated.

General

- Refer to the requirements and associated guidance for emergency shutdown systems and subsea production systems in sections 133 and 138 of the *Framework Regulations*, respectively.
- The setting depth of a SSV should consider the formation of hydrates and prevention of damage from icebergs.
- Any other hazards that could affect the ongoing operation of valves should be considered and measures put in place to address. Hazards to consider include the formation of wax, scale, corrosion, sand production, etc.
- For injection wells, the operator may use a subsurface injection valve instead of a SSV.
- Refer to requirements and associated guidance for operations and maintenance of these systems under sections 73, 153, 156, 157 and 158 of the *Framework Regulations*.

Qualification of Gas-Lift Valves as a Barrier

In the case for a gas-lifted production well, a barrier qualified (e.g., V0 rated, gas tight or equivalent) gas-lift valve installed in the production tubing may be considered as an alternative means of compliance if it can be demonstrated to provide an acceptable barrier element without increasing the risk profile. At a minimum, the following items should be assessed and discussed:

- The qualification and certification of the gas-lift valves to be used as a well barrier element. This should be conducted in accordance with *API Spec 19G2 - Flow-control devices for side-pocket mandrels*.
- The frequency and testing plan for gas-lift valves.
- Assessment of impacts of changes to the concept safety analysis and risk assessments completed under sections 24, 107 and 108 of the *Framework Regulations*, compared to if an ASV has been installed.
- Confirmation of the CA acceptance/endorsement of the alternative annular barrier philosophy and how they will manage the acceptance of the assembly being used on a per well basis.
- If the ASV or barrier qualified gas-lift valves are intended to be set deep in the well, wellhead or surface barriers should be considered and discussed with the *Regulator*.

Barrier qualified gas-lift valves and associated measures for their use should be described in documents forming the Safety Plan and in associated well approvals (e.g., maximum setting depths, maximum annular volume). The operator should continually assess the reservoir conditions and the installation risk profile to ensure that the application of this alternate approach continues to meet ALARP. If considered necessary for the ongoing management of risk, the operator should revert to the use of dedicated ASVs for subsequent well designs.

Testing

- Following installation, the frequency of testing of SSVs (e.g., DHSVs and ASVs) should follow the frequency as described in *NORSOK D-010 Well integrity in drilling and well operations.*
- In the circumstance in which reservoir pressure does not enable differential pressure testing across the SSV, an alternative means of validating these valves should be implemented. In this case, the *Regulator* should be consulted.

Standards

Guidance is provided in the following:
- *NORSOK D-010 Well integrity in drilling and well operations.*
- Classification society rules (e.g., *DNV-ST-F301 Subsea equipment and components*)

Section 166 - Well tubulars, trees and wellheads

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166 (1) An operator must ensure that well tubulars, trees and wellheads are operated in accordance with good engineering practices.

Sour environment

(2) The operator must ensure that any well tubulars, trees or wellheads that may be exposed to a sour environment are capable of operating safely in that environment.

Safe and efficient operation

(3) The operator must ensure that the wellhead and tree equipment, including any valves, are designed and maintained to operate safely and efficiently throughout the life cycle of the well under all loads to which the well may be subjected.

General

- Refer to the requirement and associated guidance for well control, physical and environmental conditions, risk assessments, electrical systems, control and monitoring systems, emergency shutdown systems, subsea production systems, drilling risers and fail-safe SSVs under sections 68, 98, 104, 106, 107, 108, 110, 122, 123, 124, 125, 133, 138, 164, 165 and 169 of the *Framework Regulations*.

- Refer to requirements and associated guidance for operations and maintenance of these systems under sections 73, 153, 155, 156, 157 and 158 of the *Framework Regulations*.
- It is interpreted that “anticipated maximum loads” include an assessment of pressure (including formation pressure), thermal stresses, mechanical loading, corrosion (including, if applicable, environments that contain H_2S, CO_2, brines or other corrosive environments), erosion, wear and all appropriate combinations of loads that may be expected. This assessment should also include an assessment of all relevant data including offset well data, seismic information and, if applicable, field production and injection data, to develop an appropriate pore pressure and fracture gradient profile for each well. Refer to the requirements and associated guidance for the well verification scheme under section 19 of the *Framework Regulations*.
- The operator should ensure that appropriate equipment, systems and procedures are in place to monitor pressures, temperatures and any other parameters necessary for ongoing reliability and integrity of the wellhead and tree.
- Guidance on drilling and well operating practices is provided in section 73 of the *Framework Regulations.*

Standards

Guidance is provided in the following:

- *NORSOK D-001 Drilling Facilities.*
- *NORSOK D-010 Well integrity in drilling and well operations.*
- Classification society rules with respect to wellhead and tree equipment.
- Equipment above the water level (surface) should conform to *API Spec 6A Specification for Wellhead and Christmas Tree Equipment*, with the exception that screwed wellhead connections should not be used – connections should be flanged and bolted.
- Equipment below the water level (subsea) should conform to *API Specification 17D Specification for Subsea Wellhead and Tree Equipment.* Refer also to the requirements and associated guidance for subsea production systems in section 138 of the *Framework Regulations*.
- Valves should conform to *API Std 6AV2 Installation, Maintenance, and Repair of Safety Valves (SSV, USV and BSDV).*
- All components that perform a safety-critical function and are located above the surface which could be exposed to fire should be protected and conform to *API Std 6FA Standard for Fire Test of Valves* and *API Spec 6FB Fire Test for End Connections* (for those components installed according to API Spec 6A).

Testing

- Operators should pressure test, function test and leak test wellhead and tree equipment upon installation and at appropriate intervals thereafter, throughout the life of the well to ensure functionality, availability and reliability. Guidance is provided in *NORSOK D-010 Well integrity in drilling and well operations.*

- In the circumstance in which reservoir pressure does not enable differential pressure testing across safety valves, an alternative means of validating these valves should be implemented. In this case, the *Regulator* should be consulted.

Section 167 - Formation Flow Test Equipment

167 (1) An operator must ensure that the equipment used in a formation flow test is designed to safely control well pressure, evaluate the formation and prevent pollution.

Rated working pressure

(2) The operator must ensure that the rated working pressure of formation flow test equipment at and upstream of the well testing manifold exceeds the maximum anticipated shut-in pressure.

Overpressure

(3) The operator must ensure that all equipment downstream of the well testing manifold is protected against overpressure.

Downhole safety valve – development well

(4) The operator must ensure, in the case of a development well, that the formation flow test equipment includes a downhole safety valve that permits closure of the test string above the packer.

Downhole safety valve — exploratory or delineation well

(5) The operator must ensure, in the case of an exploratory well or a delineation well drilled on a geological feature, that a downhole safety valve is installed before a formation flow test is conducted unless
(a) it has been demonstrated as part of the formation flow test program referred to in paragraph 63(3)(a) that the level of risk of the proposed alternative arrangement in that program is equivalent to or lower than that of using a downhole safety valve; and
(b) the Board has approved the test under subsection 63(5).

Subsea test tree

(6) The operator must 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 is equipped with

(a) a valve that can 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.

General

- Refer to the requirements and associated guidance for well control, physical and environmental conditions, hazardous and non-hazardous areas, ventilation, ignition prevention, electrical systems, control and monitoring systems, gas release systems, fire and gas detection, emergency shutdown systems, pressure systems, mechanical equipment, materials handling equipment, station-keeping systems, drilling risers and well tubulars, trees and wellheads as provided in sections 68, 98, 104, 106, 107, 108, 110, 113, 114, 115, 122, 123, 124, 125, 131, 132, 133, 135, 136, 137, 146, 147, 148, 149, 150, 164 and 169 of the *Framework Regulations*
- Formation flow testing programs require approval under section 63 of the *Framework Regulations*.
- Refer to requirements and associated guidance for operations and maintenance of these systems under sections 73, 153, 155, 156, 157 and 158 of the *Framework Regulations*.
- With respect to subsection 167(1) of the *Framework Regulations*:
  - This is interpreted to apply to all equipment used in the program including well control equipment, subsea test equipment, downhole assemblies, packers, valves, downhole gauges, surface test equipment, etc.
  - A downhole test tool, if used, should in the event of tool failure, be designed to fail in an open position to enable the continuation of the test via surface shut-in at the choke manifold.
  - The test string should be capable of reverse circulation.
  - Downhole shut-in and real-time pressure monitoring should be used. The *Regulator* will accept real-time monitoring as the basis for deviating from stated flow and shut-in period durations in an approved test program.
  - Electronic gauges for measuring reservoir pressure and temperature for pressure analysis purposes should be used. The gauge should be suited to the operational environment and test objectives. The results of gauge calibration or checks for accuracy and repeatability should be recorded and dated. The reference gauge used should have its calibration traceable to an international standard.
  - All gauges used should be calibrated before, and immediately following a formation flow test. Adequate gauge redundancy should exist to validate data and negate any effects of gauge failures.
- With respect to subsection 167(2) of the *Framework Regulations*, the rated working pressure relates to equipment upstream of and including the choke, as long as pressure relief systems are in place to protect the downstream testing equipment.

- With respect to subsection 167(4) of the *Framework Regulations,* for development wells, the SCSSV should be acceptable as a DHSV for the temporary flow back of hydrocarbons to a MODU pending tie-back to production installations.
- With respect to subsection 167(5) of the *Framework Regulations,* for exploration and delineation wells, the use of a DHSV in addition to the SSTT dual safety valves in place at the BOP level should be used. The DHSV should be placed in the string below the DHTV and above the test packer. This valve should allow shut-in of the well downhole if required in the event of a tubing leak, or in which potential exists for catastrophic loss of the BOP and SSTT (e.g., ice encroachment). The DHSV 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 DHTV is considered an operational valve and should not be used as a DHSV under this regulation.

Standards

Guidance is provided in the following:

- *NORSOK D-010 Well integrity in drilling and well operations.*
- *NORSOK D-007 Well testing, clean-up and flowback systems.*
- Associated classification society rules with respect to formation flow testing equipment.

PIPELINES

Section 168 - Pipelines

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168 (1) An operator must ensure that a pipeline is designed, constructed, installed, operated and maintained in accordance with CSA group standard Z662, Oil and Gas Pipeline Systems, as it relates to offshore pipelines.

Integrity management program

(2) The operator must ensure that the pipeline system integrity management program required by that standard is implemented and periodically updated.

General

- Although the definition of “pipeline” in Part III of the *Accord Acts* covers all process equipment upstream of the wellhead, both “pipeline” and “flowline” have been defined in section 1 of the *Framework Regulations* and “pipeline” has been defined to include a limited scope. The scope refers to export/import and inter-field transportation pipelines, and transportation pipelines to shore. It also includes the fixed steel components of an offshore loading system or offloading system. It does not apply to offshore metering systems, topsides production systems or subsea production systems which are discussed in sections 77, 135, 136 and 138 of the *Framework Regulations*.

- With respect to where the pipeline comes onshore, the jurisdiction for the pipeline falls to the onshore petroleum agency (which could be the CER, the provincial energy regulator or both).
- Refer to the requirements and associated guidance for physical and environmental conditions, risk assessments, electrical systems, control and monitoring systems, emergency shutdown systems, pressure systems and mechanical equipment under sections 104, 106, 107, 108, 122, 123, 124, 125, 133, 135, 136 and 169 of the *Framework Regulations*. In addition, any section of the *Framework Regulations* that references "pipelines" applies.
- Refer to requirements and associated guidance for operations and maintenance of these systems under sections 153, 155, 156, 157 and 158 of the *Framework Regulations*.

CSA Z662

With respect to *CSA Z662 Oil and Gas Pipeline Systems*, the following is noted:

- CSA Z662 only covers offshore steel pipelines, and does not cover pipelines made of other materials. There are also components of the offshore loading system or offloading system that are not covered by this standard. In addition, the offshore loading system itself is also included in the definition of a production installation. As such, components of these systems that are outside of the scope of this standard must refer to the requirements of sections 104, 135 and 136 of the *Framework Regulations*. Standards and guidance for the design, operation and maintenance of these systems is provided in sections 104, 135, 136 and 138 of the *Framework Regulations*.
- Instead of the CAN/CSA S471 that is referenced within the standard, refer to the ISO standards referenced under section 105 of the *Framework Regulations*.
- Pipeline safety valves should be installed on incoming and outgoing inter-field transportation pipelines between offshore platforms and the outgoing transportation pipeline. There should also be a capability to independently shutdown pipeline safety valves from interconnected installations on inter-field transportation pipelines. Refer to the requirements and associated guidance for emergency shutdown systems under section 133 of the *Framework Regulations*.
- The ability to isolate inventory along the full length of the pipeline should be considered to prevent pollution caused from damage or impairment. In addition, it will allow for flexibility in carrying out inspection, testing, maintenance or repair activities.
- CSA Z662 does not include specific requirements for hydrate prevention. In this regard, *ISO 13623 Petroleum and natural gas industries — Pipeline transportation systems* or *DNV-ST-F101 Submarine Pipeline Systems* should be considered.
- The ability to clean the lines for hydrates, wax, etc. and conduct internal inspections of the pipeline (e.g., pigging) should be considered.
- If pressure, temperature or composition cannot be maintained, consider the installation of intermediate stations to maintain pressure and temperature or to inject chemicals.

Standards

Additional guidance is provided in the following:

- *ISO 13623 Petroleum and natural gas industries — Pipeline transportation systems.*
- *DNV-ST-F101 Submarine Pipeline Systems.*
- Classification society rules respecting pipelines should be applied.

MONITORING

Section 169 - Monitoring of Systems

169 (1) An operator must ensure that an installation is equipped with a central monitoring system in the main control centre to monitor all systems whose failure could cause or contribute to an accidental event or waste.

Management of associated systems

(2) The operator must ensure that the alarm, safety, monitoring, warning and control functions associated with the systems that are monitored under subsection (1) are managed to prevent reportable incidents and waste.

Suspension of related system

(3) When a function referred to in subsection (2) is suspended or found to be impaired, the operator must ensure that the use of any related system is also suspended until
(a) in the case of a function that is suspended, that function is returned to service; and
(b) in the case of a function that was found to be impaired, measures are implemented to offset the risk of a reportable incident or waste.

Affected persons informed

(4) The operator must ensure that all affected persons are informed when a function referred to in subsection (2) is suspended and when it is returned to service.

Refer to the guidance provided in sections 123, 124 and 125 of this Guideline.

Section 170 - Deterioration

170 (1) An operator must, without delay, notify the Chief Safety Officer of any deterioration of an installation, including its systems or equipment, or of a pipeline, well, vessel or support craft if that deterioration could adversely affect safety or the environment.

Notice to certifying authority

(2) If any installation, system, equipment, pipeline or part of a well referred to in subsection (1) is within the scope of work referred to in section 31, the operator must also, without delay, notify the certifying authority of the deterioration.

Impairment rectification

(3) The operator must ensure that any impairment of an installation, including its systems or equipment, or of a pipeline, well, vessel or support craft is rectified without delay if the impairment could adversely affect safety or the environment.

Mitigation measures

(4) If it is not possible to rectify the impairment without delay, the operator must
(a) conduct a risk assessment to identify risk mitigation measures;
(b) implement those mitigation measures; and
(c) ensure that the impairment is rectified as soon as the circumstances permit.

Non-application

(5) Subsections (3) and (4) do not apply in the respect of safety-critical elements.

- Refer also to requirements and associated guidance for notification of repair, replacement or modification in section 162 of the *Framework Regulations.*
- Refer to the requirements and associated guidance under section 179 of the *Framework Regulations* for reportable incidents, which includes reporting of impairments. With respect to repairs, the time to repair and associated risk mitigation measures in the interim should be included in the associated written notification report submitted to the *Regulator*. Status updates on impairment should also be noted in daily reports provided in accordance with section 197 of the *Framework Regulations*.

PART 11: SUPPORT OPERATIONS

Section 171 – Support Craft

171 (1) An operator must, in respect of an installation on which persons are normally present, ensure that:
(a) a support craft that is at a distance from the installation not greater than that required for a return time of 20 minutes is available at all times for emergency response; and
(b) whenever an aircraft is landing or taking off, or personnel are working over the side or otherwise exposed to the risk of falling in the water, a support craft is available in the immediate vicinity of the installation and ready to undertake rescue and recovery operations.

Requirements

(2) The support craft referred to in subsection (1) must be
(a) capable of safely providing necessary support functions in the foreseeable physical and environmental conditions prevailing in the area in which it operates;
(b) equipped to supply emergency services, including rescue and first aid treatment, for all personnel on the installation in the event of an emergency; and
(c) equipped with a self-righting fast rescue boat that
- ***(i) meets the requirements under chapter V of the LSA Code,***
- ***(ii) is capable of being launched and retrieved when it is loaded with a full complement of persons and equipment, and***
- ***(iii) is ready for deployment in the event of an emergency.***

Required distance exceeded

(3) If the support craft is located at a distance that exceeds the distance referred to in paragraph (1)(a), both the installation manager and the person in charge of the support craft must log that fact and the reason why the distance or time was exceeded.

Vessel master

(4) During any activity or situation referred to in paragraph (1)(b), or any other activity or situation that presents an increased level of risk to the safety of the installation, the vessel master must, under the direction of the installation manager, keep the craft in close proximity to the installation, maintain open communication channels with the installation and be prepared to conduct rescue operations.

GENERAL

- Refer to the requirements and associated guidance for all support craft in paragraph 41(g) of the *Framework Regulations*.
- With respect to subsection 171(1) of the *Framework Regulations*, a “standby vessel” is required for operations involving an installation (i.e., drilling, production or accommodations installation). Because of the risk, standby vessels should also be present when persons are onboard a normally unattended offshore installation and when aircraft are landing or taking off from a normally unattended Installation. Guidance on standby vessels is provided in the *Standby Vessel Guideline*.

DOCUMENT OF COMPLIANCE (AC-SBV-DOC)

- The vessel’s survivor capacity as stated in the AC-SBV-DOC must at all times be adequate for the POB on the installation(s) being serviced. It is important to note that even though the vessel may be carrying a valid AC-SBV-DOC additional steps may be required to ensure it is standby compliant for the particular installation(s), specifically:
  - The vessel’s AC-SBV-DOC may include certain annotations that may restrict it from standby duty for particular installations (e.g., the vessel may not be fitted with H_2S/hazardous gas detection equipment or the crew may not have the relevant training).
  - In order to be standby compliant the vessel’s crew should be provided with certain information and training on the specific installation(s) to be serviced (refer to section 4 of the *Standby Vessel Guideline* for details).
  - Depending on the timing of the last AC-SBV-DOC survey, some of the items such as drills, equipment maintenance and crew training may no longer be up-to-date by the time the vessel is taken on charter.
  - The vessel may further have to comply with any additional requirements relevant to the specific project (e.g., installation and iceberg towing capabilities), or as otherwise specified by the operator’s functional specification referenced above.

Section 172 – Rescue Boat - Vessel

172 An operator must, in respect of any vessel that is used in a geoscientific program, geotechnical program, environmental program, diving project or construction activity, ensure that a rescue boat is available and ready for use in the event of an emergency.

With respect to section 172 of the *Framework Regulations* and paragraph 29(c) of the *OHS Regulations*, a fast rescue boat, also referred to as a FRC, must be available and ready for immediate deployment during any operation in which there is a risk of people falling in the water and should also be available during any associated aircraft landing and takeoff. Refer to associated guidance provided paragraph 29(c) of the *Guideline for the Occupational Health and*

Safety Regulations. The fast rescue boat crew and the launching team should be dedicated to that role and not double-tasked.

Section 173 – Safety Zone

173 (1) A support craft must not enter the safety zone around an installation or around a vessel that is engaged in a geoscientific program, geotechnical program, environmental program or diving project without the consent of the installation manager or the person in charge of the operations site.

Notice to approaching aircraft or vessel

(2) The operator must ensure that persons who are in charge of an aircraft or vessel that is approaching the safety zone are notified of the safety zone boundaries and of any hazards within that zone that relate to the operator's installation or vessel.

Boundaries — installation

(3) The safety zone around an installation consists of the area within a line that encloses the installation and is drawn at a distance of 500 m from the outer edge of the installation or, if any component of the installation extends beyond that edge, from the outer limit of the component that extends furthest from that edge.

Boundaries — vessel

(4) The safety zone around a vessel referred to in subsection (1) consists of the area within a line that encloses the vessel and any of its attached equipment and is drawn at a distance that minimizes risks to safety, the environment and property located nearby, including fishing gear or fishing vessels.

Entry into Safety Zone

With respect to subsection 173(1) of the *Framework Regulations* and consistent with industry best practices, operators should have detailed procedures and associated checklists in place for ensuring that all navigation, station keeping and other critical safety equipment is tested on support craft or other vessels or aircraft before being given permission to enter the safety zone. With respect to an aircraft, operators should also adhere to the requirements for approach under the *Canadian Aviation Regulations.*

Safety Zones – General

Operators should also refer to Article 60 of UNCLOS and Rule 43 of the *Collision Regulations* for requirements respecting safety zones for marine support craft and to any requirements under the *Canadian Aviation Regulations* for aircraft.

Safety Zones – Diving Project

For diving projects, the safety zone should be selected based on the risk to divers and to the installation or vessel and should factor in other issues that can affect the divers like noise that may be produced from adjacent operations, etc.

Safety Zones – Geoscientific Programs

For geoscientific programs, the safety zone should be selected based on the minimum distance that should be maintained from the installation or vessel and the deployed seismic equipment. It should also consider any commitments or conditions of associated Environmental Assessments and Impact Assessments.

Charting of a Safety Zone

With respect to subsections 173(2) and (3) of the *Framework Regulations*, before installing or placing equipment on site, operators of fixed installations (which includes any fixed subsea assets) should contact the Canadian Hydrographic Service to have the Safety Zone associated with the fixed installation added to appropriate nautical charts.

Notice to Mariners/Notice to Shipping

With respect to subsections 173(2), (3) and (4) of the *Framework Regulations,* for installations or vessels in the *Offshore Area* for a short-term basis, the operator should communicate the appropriate information regarding location and Safety Zone to the CCG within the DFO, so they can ensure a “Notice to Mariners” or “Notice to Shipping” is issued.

Sections 174 - 176 - Landing Areas

Landing area

174 (1) An operator must ensure that the aircraft landing area on an installation or vessel and the equipment that is used in that area or that otherwise supports the take-off or landing of aircraft are designed to ensure safety and the protection of the environment and to prevent incidents or damage resulting from the use of aircraft.

Requirements

(2) The operator must ensure that the landing area
(a) has an obstacle-free take-off and approach area and is oriented relative to prevailing winds;
(b) can withstand all functional loads imposed by aircraft;
(c) can accommodate aircraft of expected sizes;
(d) has emergency response and firefighting equipment;
(e) has conspicuous markings and signage;
(f) has adequate lighting, including in reduced visibility conditions;
(g) has monitoring and status light systems and communication and meteorological equipment;
(h) is readily and safely accessible, including from the accommodations areas and from any temporary safe refuge; and
(i) in the case of a landing area on an installation, it is equipped with fuel storage tanks.

Fuel storage tanks

(3) The operator must ensure that any fuel storage tanks that are in proximity to a landing area are stored safely and protected from damage, impact or and fire.

Procedures

175 The operator must ensure the establishment of procedures associated with the support of aircraft operations, including procedures for emergency response, and of a training program for personnel for those purposes.

Aircraft service provider

176 An operator must ensure that, before the start of any operations that require the use of an aircraft, the aircraft service provider has accepted in writing all conditions with respect to the use of the equipment in any landing area, the procedures associated with the support of aircraft operations, including the procedures for emergency response, and the training program for personnel in respect of those matters.

General

- Refer to the requirements of the *Canadian Aviation Regulations* as it pertains to the aircraft, associated equipment onboard an installation or vessel (e.g., obstruction marking and lighting, communications equipment), associated training or instruction, observations and forecasts of physical and environmental conditions, operating procedures and associated limitations.
- Landing areas and associated operations onboard safety convention vessels should meet the requirements of the following:
    - SOLAS, flag state and classification society rules for safety convention vessels.

- *CAP 437 Standards for Offshore Helicopter Landing Areas.*
- Additional guidance is also provided in the following:
  - *CAA Paper 2008/03: Helideck Design Considerations – Environmental Effects.*
  - *UKOOA Guidelines for the Management of Offshore Helideck Operations.*
  - *International Chamber of Shipping (ICS) Guide to Helicopter/Ship Operations.*

- Although guidance is provided in the CAP, CAA, UKOOA and ICS references noted above, these documents reference agencies, committees, authorities, requirements and EN standards that are used in the United Kingdom. Any requirement under the *Accord Acts* and associated regulations will prevail in the event of a conflict. There are some requirements within CAP 437 that may not be suitable in the *Offshore Area* (e.g., helideck net should be installed on all floating installations or vessels during any time of the year and onboard fixed installations during cold climate operations. If a low profile helideck net is planned to be used, it may require operational restrictions to be imposed upon its use). In addition, instead of the guidance in CAP 437 for weather forecasting and reporting, refer to the requirements of the *Canadian Aviation Regulations*.
- As all related requirements for the landing area as stated in the *Framework Regulations* may not be covered by the class certificate, installation and vessel owners should ensure that fuel quality checks, inspection, testing and maintenance onboard is equivalent to CAP 437 and acceptable to the aircraft service provider. Installation and vessel owners should consider maintaining a class notation for the landing area (e.g., helicopter deck) given the physical and environmental conditions and remoteness of the *Offshore Area*.
- Additional design considerations are as follows:
  - Drainage systems from the landing area should be designed to drain to an appropriately designed drainage system according to CAP 437 as opposed to draining directly overboard unless otherwise accepted under the Environmental Protection Plan.
  - Although most standards and rules require certain equipment be located at or near the landing area, operators and aircraft services providers should include in their risk assessments a review of the different scenarios that could occur and should ensure that appropriate measures are implemented. This should include the placement of any additional equipment (e.g., backup aircraft starting equipment, spill kits, equipment for removing snow or ice, accurate means for measuring weights of persons and cargo, the provision of a Class D fire extinguisher suitable for fires involving combustible metals on the helicopter), operations and maintenance procedures and training and competency of persons in the use of the equipment (e.g., drills) and procedures.
  - For drilling, production and accommodations installations:
    - Refer to the requirements and associated guidance for physical and environmental conditions, design for intended use and location, aircraft impact and environmental effects under sections 104, 105 and 106 and subsection 131(4) of the *Framework Regulations*. Additional guidance for the design of helidecks and the consideration of environmental effects is also provided in *ISO 19901-3 Oil and gas industries including lower carbon energy – Specific requirements for offshore structures – Part 3: Topsides Structure*.
    - Refer to the requirements and associated guidance for risk assessments under sections 107 and 108 of the *Framework Regulations*. Additional guidance is provided

in *ISO 13702 Petroleum and natural gas industries — Control and mitigation of fires and explosions on offshore production installations* and CAP 437.

- Refer also to the requirements and associated guidance for risk assessments, hazardous and non-hazardous areas, ignition prevention, escape, electrical systems, control and monitoring systems, communication systems, gas release systems, fire and gas detection, fire protection systems, pressure systems and mechanical equipment under sections 98, 107, 108, 110, 113, 115, 116, 118, 122, 123, 124, 125, 126, 129, 131, 132, 134, 135, 136 and 169 of the *Framework Regulation*s.
- Refer to requirements and associated guidance for operations and maintenance of these systems under sections 153, 155, 156, 157 and 158 of the *Framework Regulations*.
- For MODUs, refer also to the MODU Code.
- Operators should also install an automatic visual warning system either on or adjacent to the landing area, if a condition can exist (such as an impending gas release or physical and environmental conditions) that may be hazardous for the aircraft or its occupants.
- Operators should also provide appropriate ground fault detection or earth proving systems on the aircraft refueling system.

Operational Considerations

- Operators and aircraft services providers should ensure procedures and checklists include criteria for all physical and environmental conditions (e.g., high winds, light to no wind conditions, wind direction, ceiling, visibility), locations of exhausts, flares or cold vents and limitations caused by turbulence from structures. These criteria should be reported to aircraft pilots as part of flight planning, if changes occur during the flight and before landing.
- Operators and aircraft services providers should monitor the position of all vessels during the aircraft's approach to the installation.
- For aviation weather forecasting and reporting, refer to the requirements and associated guidance under section 109 of the *Framework Regulations*.

Training

- Refer to specific training requirements in the *OHS Regulations*, the *Canadian Aviation Regulations* and CAP 437.
- For drilling, production and accommodations installations, additional guidance on training is provided for the helicopter deck team, helicopter landing officer, environmental observer and radio operator in the COP TQOP.

Inspection by Aircraft Service Provider

With respect to section 176 of the *Framework Regulations*:

- The acceptance of the landing area and associated equipment is interpreted to cover any associated fueling and fuel storage areas.

- Any deficiencies against the regulations or non-conformances to operator and aircraft service provider requirements should be addressed before the start of flight operations.

Section 177 - Classification

177 An operator must ensure that any support or construction vessel to be used in conjunction with an installation holds a valid certificate of class issued by a classification society according to the work or activity to be carried out by it.

- Refer to the definition of "classification society" in the *Framework Regulations*.
- The operator should ensure that in addition to base class requirements, any relevant "class notations" or "certifications" are in place and appropriate for the activities that the support vessel or construction vessel is intended to perform.
- With respect to construction vessels, the following class rules should be considered for the vessel itself:
  - DNV rules for ships and any provisions in relation to the class of activities it is performing.
  - LR rules for ships and any provisions in relation to the class of activities it is performing.
- Refer to IMO Conventions (e.g., SOLAS, MARPOL, Loadline), resolutions and associated circulars for stability, life-saving appliances, structural fire protection, pollution prevention arrangements and fire detection and extinction arrangements that may not be covered in classification society rules.
- Classed for the "work or activity" should be interpreted that the classification society has assessed and issued certification, a notation or equivalent in respect of any equipment intended to be used during the program such as materials handling equipment, helidecks, DP systems, pressure systems, etc.
- Support and construction vessels should also be suitable for operations in the environment in which they are intended to work and operational limits should be established, communicated and adhered to during the program.

PART 12: NOTICES, RECORDS, REPORTING AND OTHER INFORMATION

GENERAL

Section 178 - Definitions

Definition of shotpoint

178 In this Part, shotpoint means the surface location of a seismic energy source.

No guidance required at this time.

Section 179 - Reportable Incidents

179 (1) An operator must notify the Board of a reportable incident as soon as the circumstances permit, but not later than 24 hours after becoming aware of the incident.

Investigation

(2) The operator must ensure that
(a) any reportable incident is investigated;
(b) the person who conducts the investigation includes in their investigation report the root causes of the reportable incident, the contributing factors, measures to be implemented to prevent its recurrence and any other relevant information; and
(c) the investigation report is submitted to the Board not later than 14 days after the day on which the reportable incident occurred.

- Refer to the requirements for the reporting and investigation of incidents, accidents and hazard occurrences in the *Accord Acts*[30].
- Refer to the definition of “reportable incident” and the requirements and associated guidance in sections 162 and 170 of the *Framework Regulations*.
- Refer to the *Incident Reporting and Investigation Guideline*.

[30] C-NLAAIA 160, 161, 165, 205.015, 205.017 and 205.02; CNSOPRAIA 165, 166, 170, 210.015, 210.017 and 210.02

Section 180 - Accessibility of Records

180 An operator must ensure that any records that are necessary to support operational requirements and the requirements of these Regulations are readily accessible to the Board for examination.

- Refer to the requirements and associated guidance for management and accessibility of records in Part 3 and section 48 of *Framework Regulations*.
- Specific requirements for records are also prescribed in the *Accord Acts* and associated regulations.
- Specific requirements for provision of records to officers are in the *Accord Acts* and requirements prohibiting records from containing false or misleading information.
- If a record is required to be generated in accordance with a code or standard that has been adopted, this record should also be made available.

Section 181 - Critical Information (All Works or Activities)

181 (1) An operator must ensure that records are kept of all information – including the following – that is critical to safety, the protection of the environment or the prevention of waste:
(a) information on the location and movement of support craft;
(b) information on reportable incidents;
(c) information on emergency drills and exercises;
(d) information on the quantities of consumable substances at any operations site;
(e) data resulting from any required observation of wildlife;
(f) information on verification, inspection, monitoring, testing, maintenance and operating activities;
(g) information on the status of all systems and equipment identified in the safety plan as being critical to safety or in the environmental protection plan as being critical to the protection of the environment, including any test result indicating that the systems or equipment are not functioning as intended and information on any equipment failure that has led to an impairment of any of those systems; and
(g) information on the physical and environmental conditions observed and forecasted under section 42.

Record retention periods

(2) The operator must retain the records referred to in subsection (1) for the following periods:

(a) in the case of the records referred to in paragraphs (1)(a) and (e) to (g) and those referred to in paragraph (1)(h) regarding forecasted conditions, five years after the day on which the record is created;
(b) in the case of the records referred to in paragraph (1)(b) and (c),
(i) five years after the day on which the drill or exercise is carried out, and
(ii) 10 years after the day on which the reportable incident is reported;
(c) in the case of the records referred to in paragraph (1)(d), for as long as the consumable substance is at the operations site; and
(d) in the case of the records referred to in paragraph (1)(h) regarding conditions observed, for the duration of the authorized work or activity.

- Refer to the requirements and associated guidance for management and accessibility of records in Part 3 and section 48 of the *Framework Regulations*.
- In addition to these requirements, refer to any specific requirements for records prescribed in the *Accord Acts* and the regulations and any other requirement of the *Regulator*. Attention should also be paid to provisions related to retention of records, provisions related to submitting records to the *Regulator* and the provisions related to offering up records to the *Regulator* before they are destroyed. Operators should ensure that the processes within their management system include these requirements.
- Specific requirements for provision of records to Officers are in the *Accord Act* and requirements that prohibit these records from containing false or misleading information.
- It is not necessary that a single combined record be kept of the various topics listed above. 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.

Section 182 - Safety Report

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182 (1) An operator must ensure that a safety report that relates to an authorized work or activity conducted in a given calendar year is submitted to the Board within 90 days after the day on which the work or activity is concluded or suspended or, in the case of a work or activity that will continue into the following calendar year, that a safety report that relates to the work or activity conducted in the preceding calendar year is submitted to the Board not later than March 31st of that following calendar year.

Requirements

(2) The safety report must include
(a) a description and analysis of the efforts undertaken to improve safety;
(b) a summary of the operator's safety performance during the applicable calendar year, including with respect to the objective of reducing safety risks;

(c) a summary of the safety measures and actions taken to mitigate the effects of any reportable incident, as well as of their effectiveness and any adjustments made for their continued improvement; and
(d) a summary of any emergency response drills and exercises relating to safety that were completed.

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a. General

- All reports submitted to the *Regulator* should be accurate, complete and provided in a searchable electronic format (e.g., PDF).
- All reports should be submitted to the C-NLOPB at information@cnlopb.ca or to the CNSOPB at info@cnsopb.ns.ca.
- All reports should either be submitted to the *Regulator* or made available electronically for download.

b. Safety Report

- Refer to the requirements of the *Accord Acts*[31] for additional requirements for safety reports. In accordance with the *Accord Acts*:
  - A copy of the report must be provided to the workplace committee, for active OAs.
  - The report must cover all of the operator's workplaces and passenger craft going to or from any of these workplaces.

  In addition:
  - Reports should consider any conditions or commitments associated with observation or reporting from associated *Development Plans*, authorizations, approvals or RQs.
  - Reports should also include any commitments that have been established in any MOU.
- With respect to paragraph 182(a) of the *Framework Regulations*, the safety report should include an analysis of risk trends and associated root causes of non-compliances, hazardous occurrences, incidents, etc., and summarize the efforts that will be undertaken to reduce safety risks.
- With respect to paragraphs 182(b) and (c) of the *Framework Regulations*, the safety report should include a summary of key performance indicators used to measure the performance of the management system and the associated results. This should include:
  - Incidents by actual and potential classification type (refer to classifications in the *Incident Reporting and Investigation Guideline*).
  - Other reportable events (refer to other reportable events in the *Incident Reporting and Investigation Guideline*).
  - Hazardous occurrences which should include a summary of behavioral based observations, hazard identification cards or other similar reports generated.
  - Any failures to comply with the management system, including any non-compliances noted during the operator's associated audits and inspections.

[31] C-NLAAIA 205.017(3) & (4); CNSOPRAIA 210.017(3) & (4)

- A summary of issues with respect to the integrity of production, drilling or accommodations installations, including:
  - a summary of the status of systems critical to safety throughout the year;
  - the current backlog of preventative inspection, testing and maintenance on systems critical to safety;
  - the current backlog of corrective maintenance to be completed on systems critical to safety, along with an assessment of whether the maintenance is critical or not critical in meeting the associated performance standard;
  - all unrevealed critical failures to detection, control and monitoring systems from planned or unplanned testing and the comparison of this data to the reliability/availability of systems critical to safety or protection of the environment against assumptions made during risk assessments regarding their performance; and
  - plans to address systems unable to meet associated performance standards.

c. Quarterly Statistics Reports

To enable more frequent monitoring by the *Regulator*, operators should submit a quarterly statistics report within 15 days of the end of each quarter throughout the calendar year. In addition, the operator should submit a final statistics report within 15 days of the date of completion of work or activities under an OA.[32]

This report should contain a list of major injuries, lost/restricted workday injuries, occupational illnesses and minor injuries along with exposure hours.[33] This report should include a summary report of the number of lost/restricted workdays associated with a particular injury/illness by incident date and the installation, passenger craft, vessel or aircraft.[34] These statistics should be provided on the Quarterly Statistics Report form and emailed to either the C-NLOPB at incident@cnlopb.ca or to the CNSOPB at incident@cnsopb.ns.ca. The Quarterly Statistics Report form is posted on the *Regulators*' websites.

To enable comparison of trends across the industry, exposure hours should be reported as follows for each type of installation, vessel and aircraft on the report prescribed by the *Regulator*, including:

- Total exposure hours for each primary installation or vessel based on a normal working day (i.e., 12 hours).
- Total exposure hours on all vessels operating under the OA (excluding passenger exposure hours) based on a normal working day (i.e., 12 hours).
- Total exposure hours for all aircraft operating under the OA (excluding passenger exposure hours).
- Total exposure hours for passengers on a vessel (excluding crew).
- Total exposure hours for passengers on an aircraft (excluding pilots).

[32] C-NLAAIA 49, 126, 189-192, 205.017(3)(4); CNSOPRAIA 52, 129, 194-197, 210.017(3)(4); MOU with Federal and Provincial Governments for Part III and Part III.I of the *Accord Acts*
[33] C-NLAAIA 49, 126, 189-192, 205.017(3)(4); CNSOPRAIA 52, 129, 194-197, 210.017(3)(4)
[34] C-NLAAIA 49, 126, 189-192, 205.017(3)(4); CNSOPRAIA 52, 129, 194-197, 210.017(3)(4)

Section 183 - Annual Reports

183 An operator must ensure that the Board is made aware, at least once a year, of any report containing relevant information regarding applied research work or studies that the operator has participated in, funded or commissioned concerning the operator's authorized works and activities in relation to safety, the protection of the environment or resource management and must ensure that a copy of the report is submitted to the Board on request.

In NL, refer to section 5.1 and Appendix 2 of the *Benefits Plan Guideline* for production projects, including any associated production, drilling, construction, diving and GGE activities, and refer to Appendix 1 for exploration or delineation drilling programs and GGE activities not associated with a production project. In NS, refer to section 3.9 and Appendix V of the *Canada-Nova Scotia Benefits Plan Guidelines*. Reports for the C-NLOPB should be sent to information@cnlopb.ca and reports for the CNSOPB should be sent to info@cnsopb.ns.ca.

GEOSCIENTIFIC, GEOTECHNICAL AND ENVIRONMENTAL PROGRAMS

Section 184 – Notice - Key Dates

184 When any geoscientific program, geotechnical program or environmental program is commenced, concluded, suspended or cancelled by an operator, the operator must, without delay, notify the Board in writing of the date of the commencement, conclusion, suspension or cancellation of the program.

For this section, the terms are interpreted as follows:

Commenced	A program is considered commenced when an OA has been issued
Concluded	A program is considered to be concluded when the authorized activities have permanently ceased
Suspended	A program is considered to be suspended when the authorized activities have temporarily ceased
Cancelled	A program is considered to be cancelled when the operator no longer intends to undertake the authorized work or activity

A program is considered concluded or suspended when all equipment associated with the activity has been retrieved to deck, all transfers or bunkering of cargo or persons while in transit to a port are completed or the vessel has left the *Offshore Area*.

All notifications for the CNSOPB should be sent to info@cnsopb.ns.ca and all notifications for the C-NLOPB should be sent to exp@cnlopb.ca and information@cnlopb.ca. This notification must also be provided if the GGE program is being conducted as part of a drilling program or production project.

Section 185 – Weekly Status Report

185 (1) An operator must ensure that weekly reports are submitted to the Board on the status of field work carried out in relation to any geoscientific program, geotechnical program or environmental program from the commencement of the program until its conclusion, suspension or cancellation.

Content of reports

(2) The weekly status reports must contain the following documents and information:
(a) the program number assigned by the Board;
(b) information identifying, and indicating the current location and status of, all operations sites and support craft used in the program;
(c) key dates of the works and activities under the program, in particular their commencement, suspension and completion dates,
(d) a description of the works and activities carried out during the preceding week, including
> ***(i) the quantity of data collected, broken down by data acquisition technique,***
> ***(ii) information identifying and indicating the location of data collection points, lines or areas,***
> ***(iii) a schedule indicating each type of work or activity carried out under the program, as well as any period in which data acquisition was delayed or interrupted, along with a summary of the causes of that delay or interruption, and***
> ***(iv) a description of any failure to comply with a condition of the authorization;***

(e) maps illustrating, in relation to the proposed data acquisition plan referred to in subparagraph 8(i)(iii), the portion of the data acquisition that has been completed, the portion that was completed in the preceding week and the portion that remains to be carried out;
(f) an indication of the total number of persons involved in the program who, during the preceding week, were at, or transferred to or from, the operations sites and if applicable, the means by which they were transferred;
(g) a summary of any communications or interactions that occurred during the preceding week concerning program activities between persons associated with the program and persons associated with fishing activities;

(h) a summary of emergency drills and exercises that were completed and reportable incidents that occurred during the preceding week;
(i) an indication of the quantities of consumable substances that are critical to safety that are currently at each operations site;
(j) all wildlife observation data from the preceding week that were required to be recorded under paragraph 181(1)(e);
(k) a summary of the verification, inspection, monitoring, testing, maintenance and operating activities that are critical to safety that were carried out during the preceding week; and
(l) a description of any measures taken during the preceding week to avoid disturbing wildlife or interfering with fishing activities or any other uses of the sea.

General

- During the final stages of the OA process, operators should consult with the *Regulator* to discuss the template and format of the weekly status report as details may need to be included specific to the acquisition for which the approval is being sought. In NL, by completing the weekly status report template as discussed with the *Regulator*, the operator will fulfill the reporting requirement of section 185 of the *Framework Regulations*.
- Weekly status reports should cover the period from the date the program is commenced to the date the program is concluded. In the case in which a program is suspended, reports are still required to be submitted during the suspension timeframe.
- Weekly status reports should be submitted every Monday by 1200 (UTC) and the reporting period should cover 0000 (UTC) Monday to 2400 (UTC) Sunday.
- All weekly status reports submitted to the *Regulator* should be accurate, complete and provided in a searchable electronic format (e.g., PDF).
- All weekly status reports should be submitted to the C-NLOPB at exp@cnlopb.ca or to the CNSOPB at info@cnsopb.ns.ca.
- All reports should either be submitted to the *Regulator* or made available electronically for download.

Content

With respect to subsection 185(2) of the *Framework Regulations*, the following information should also be included on the weekly report:

- Any applicable information such as operator and location information.
- Any conditions or commitments for observation or reporting in associated Environmental Assessments and Impact Assessments or other requirements as specified in the OA.

Additional clarity is provided on requirements as follows:

- With respect to paragraph 185(2)(b) of the *Framework Regulations*:
  - support craft includes all vessels or aircraft (e.g., chase vessels, passenger craft); and
  - operations site includes all installations, vessels (e.g., data acquisition vessel) or aircraft (e.g., used for data acquisition).

- With respect to subparagraph 185(2)(d)(i) of the *Framework Regulations*, data acquisition techniques refers to each survey method used (e.g., water sample, core, waverider locations, line (2D seismic or CSEM) or polygonal data (3D seismic)).
- With respect to subparagraph 185(2)(d)(ii) of the *Framework Regulations*, delays, interruptions or non-productive time would include issues with deploying gear, standby for adverse physical and environmental conditions, mechanical failures, etc.
- With respect to paragraph 185(2)(g) of the *Framework Regulations*, communications or interactions with fishing activities should also include any interaction with fishers (such as radio communications, visual observations or formal communications with their relevant organizations) or fishing gear (physical contact with fishing gear by any part of the vessel or attached equipment or visual sightings).
- With respect to paragraph 185(2)(j) of the *Framework Regulations*, wildlife observation data should include any marine mammals, sea turtles or seabirds and any details of shutdowns or other mitigations, if applicable.
- With respect to paragraph 182(2)(k) of the *Framework Regulations*, this should include the dates that workplace committee meetings were held.

Section 186 – Environmental Report

186 An operator must ensure that an environmental report that contains the following documents and information is submitted to the Board within 90 days after the day on which a geoscientific program, geotechnical program or environmental program is concluded or suspended:
(a) a description of the general physical and environmental conditions under which the program was conducted and, if applicable, a description of ice management activities and non-productive time caused by meteorological or ice conditions;
(b) a summary of program performance in relation to the environment, including with respect to the objectives of reducing environmental risks;
(c) a summary of environmental protection measures and actions that were taken to mitigate the effects of any reportable incident, as well as of their effectiveness and adjustments made for their continued improvement;
(d) a summary of any emergency response drills and exercises for the protection of the environment that were completed; and
(e) all wildlife observation data that were required to be recorded under paragraph 181(1)(e).

- This section applies to any activities that are conducted under a geoscientific, geotechnical or environmental program that is being conducted separately from a production project or an exploration or delineation drilling program. For submission of environmental reports in relation to an exploration or delineation drilling program or a production project, refer to sections 200 and 201 of the *Framework Regulations*, respectively.

- These reports should also consider any conditions or commitments associated with observation or reporting from associated Environmental Assessments and Impact Assessments.
- All reports submitted to the *Regulator* should be accurate, complete and provided in a searchable electronic format (e.g., PDF).
- All reports should be submitted to the C-NLOPB at information@cnlopb.ca or to the CNSOPB at info@cnsopb.ns.ca.
- All reports should either be submitted to the *Regulator* or made available electronically for download.
- With respect to paragraph 186(a) of the *Framework Regulations*, the report should include a summary of the physical and environmental conditions relevant to the safe and environmentally responsible conduct of the activity. The raw physical and environmental data collected during the program should be provided in digital format.
- With respect to paragraphs 186(b) and (c) of the *Framework Regulations*, this summary should include:
    - a summary of all environmental incidents, the results of the root cause analysis of each incident and associated follow-up and corrective actions;
    - a summary of all discharges and emissions and their ultimate fate including efforts to reduce waste discharges or to reduce the effects individual wastes may have in the receiving environment;
    - a summary of identifiable common issues or trends from all leading and lagging indicators associated with environmental protection and performance; and
    - a summary of continuous improvement of environmental management systems and associated environmental performance.
- With respect to paragraph 186(d) of the *Framework Regulations*, this should include a summary of spill contingency planning exercises or any other environmental contingency planning exercises.
- With respect to paragraph 186(e) of the *Framework Regulations*, wildlife observation data should include birds, mammals, sea turtles, etc., their condition upon observation and any action taken.

Sections 187 - 188 – Final Reports

187 (1) An operator must ensure that a final operations report, final data processing report and final interpretation report are submitted to the Board with the acquired data referred to in subsection (5), as applicable, within 12 months after the day on which any geoscientific program, geotechnical program or environmental program is concluded, unless a longer period has been agreed to in writing by the Board.

Content of final operations report

(2) The final operations report must contain the following documents and information:

(a) the program number assigned by the Board;
(b) the title, author and date of the report;
(c) an executive summary and table of contents;
(d) the names of the operator, contractors and any interest owner, as defined in section 47 (or 49) of the Act;
(e) a description of all operation sites and any support craft used for the program;
(f) a description of the program, including
- *(i) key dates, in particular its commencement, suspension and completion dates,*
- *(ii) the equipment used,*
- *(iii) the operational methods employed,*
- *(iv) the number of persons who were involved in the program, and*
- *(v) the quantity of data collected, broken down by data acquisition technique;*

(g) location maps illustrating details of the data acquisition activities carried out under the program, including the identification and location of data collection points, lines or areas and the type of data acquired;
(h) location maps illustrating the boundaries of each area covered by the program and any portion of those areas that is subject to an interest, as defined in section 47 (or 49) of the Act, as well as the identification number of each such interest;
(i) a schedule that specifies the type and duration of all program activities and includes any period in which data acquisition was delayed or interrupted;
(j) an indication as to the accuracy of the navigation system and of the positioning and survey systems, as well as the parameters and configuration of both the energy source and recording system; and
(k) shotpoint maps, track plots, flight lines with numbered fiducial points, gravity station maps, location maps for any samples or core holes, copies of any photographs and a list of any videos.

Content of final data processing report

(3) The final data processing report must contain the following documents and information:
(a) the documents and information referred to in paragraphs (2)(a) to (d), (g) and (k);
(b) a description of the program, including the quantity of data collected, broken down by data acquisition technique; and
(c) a description of the geoscientific data acquired, including the data processing sequence and parameters.

Content of final interpretation report

(4) The final interpretation report must contain the following documents and information, as applicable:
(a) the documents and information referred to in paragraphs (2)(a) to (e);
(b) bathymetric or topographic maps compiled from the data collected;
(c) a description and interpretive maps of the acquired data, including:
- *(i) time and depth structure and isopach maps, velocity and residual velocity maps and seismic attribute maps,*

(ii) final Bouguer gravity maps and any residual or other processed gravity maps,
(iii) final total magnetic intensity contour maps and any residual, gradient or other processed magnetic maps,
(iv) final controlled-source electromagnetic resistivity maps,
(v) surficial maps generated from any seabed, geohazard or pipeline route survey, and
(vi) any geological maps;

(d) a description and analysis of the interpretation of the data with respect to
(i) geological and geophysical correlations,
(ii) correlations between gravity, magnetic, seismic and controlled-source electromagnetic data, including correlations to any data acquired during previous surveys,
(iii) in the case of seabed surveys, the geophysical correlation between shallow seismic data and data from cores and geotechnical boreholes,
(iv) corrections or adjustments that were applied to the data during processing or compilation,
(v) the velocity information that the operator used in a time-to-depth conversion,
(vi) cores and samples,
(vii) other geoscientific and geotechnical analyses, and
(viii) geohazards; and

(e) a description of
(i) synthetic seismograms,
(ii) seismic modelling studies that use synthetic seismograms,
(iii) vertical seismic profiles at wells that were used in the interpretation of the data,
(iv) amplitude versus offset studies,
(v) seismic inversion studies, if any, and
(vi) any other seismic studies related to the program.

Acquired data

(5) The following acquired data that must accompany the final reports, as applicable:
(a) time-stamped track plot, shotpoint and sample location data;
(b) bathymetric data;
(c) all final processed seismic data for each 2-D seismic line in time and depth;
(d) all final processed 3-D volumes and each line generated from that volume in time and depth;
(e) any vertical seismic profiles, synthetic seismograms, amplitude versus offset data and seismic inversion data;
(f) in the case of any seabed, geohazard or pipeline route survey,
(i) processed high-resolution data for each line,
(ii) digital location maps for any samples,
(iii) any photographs and videos, and
(iv) sub-bottom profiler and side-scan sonar data;
(g) in the case of an environmental program, any photographs, video or other graphic information that is relevant and contributes to the interpretation of the final data and the drafting of the final report;

(h) in the case of a gravity or magnetic survey, a series of gravity and magnetic profiles across all gravity and magnetic surveys; and
(i) in the case of controlled-source electromagnetic data, final processed cross-sections on all receiver lines, curves from all receivers and 2-D and 3-D final models generated.

Incorporation of previous data

(6) The operator must incorporate into any map referred to in paragraph 4(b) that is included in a final interpretation report any data previously collected by the operator that are related to the area covered by the map and that are of a type similar to the data from which the map was produced.

Exception – data made available to public

188 (1) An operator that has conducted a geoscientific program, a geotechnical program or an environmental program need not submit a final interpretation report if the data acquired from the program are made available to the public for purchase or use under licence.

Data no longer available

(2) If the operator ceases to make data available for purchase or use under licence, the operator must ensure that, within 12 months after the day on which the operator ceased to make the data available, the final interpretation report is submitted to the Board.

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a. General

With respect to sections 187 and 188 of the *Framework Regulations*, all GGE programs with and without fieldwork are subject to final submission requirements following completion.

Program submission requirements include applicable final reports, associated data and other materials produced as a result of studies. Refer to the guidance below detailing general submission requirements along with associated tables illustrating specific submission requirements for individual survey methods used as part of the authorized GGE program, whether the approved program is carried out with or without fieldwork.

Program submission requirements should consider any conditions or commitments associated with observations or reporting from associated Environmental Assessments and Impact Assessments.

Program submission requirements must be of prescribed formats and submitted via mediums acceptable to the *Regulator* as detailed below.

For any program, operators are responsible for all costs (e.g., fees, duty) related to the shipping of materials (e.g., reports, data, core, cuttings). Any charges incurred by the *Regulator* will be invoiced to the operator.

Submissions to the *Regulator* in relation to an approved GGE program may be released publically once the assigned privilege period expires. For more information on privilege periods refer to the following:

- In NL, refer to the *Disclosure of Digital Data and Information Policy.*
- In NS, contact the CNSOPB for information on data disclosure.

Final reports should be:

- created in digital format (searchable PDF) and contain:
  - written discussions;
  - figures (informative or interpretative) such as maps, diagrams, tables, enclosures, etc. In regards to using figures consider the following:
    - figures should be clearly annotated, include legends and be of appropriate resolution for readability in which quality is maintained when magnified or reproduced; and
    - scales should be selected appropriately to best represent the data at a workable level of detail; and
- signed by a professional scientist or engineer.

b. Final Operations Report

With respect to subsection 187(2) of the *Framework Regulations*, the final operations report describes the technical aspects of the survey methods and equipment used as part of a GGE Program. In addition to a general description of the survey equipment used, it should also include the following, as applicable:

- With respect to paragraph 187(2)(c) of the *Framework Regulations,* an introduction and list of enclosures.
- With respect to paragraph 187(2)(e) of the *Framework Regulations*, a description of all vessels or aircraft used for the program including the owner and for vessels, the flag of registry.
- With respect to subparagraph 187(2)(f)(i) of the *Framework Regulations*, mobilization and demobilization dates should also be identified.
- With respect to subparagraph 187(2)(f)(ii) of the *Framework Regulations*, the components of any detector, navigation (including depth) and recording systems should be described.
- With respect to subparagraph 187(2)(f)(iv) of the *Framework Regulations*, the nationality of the persons involved in the program should also be identified.
- With respect to paragraph 187(2)(i) of the *Framework Regulations*, a summary of factors that caused significant delays or interruptions should be described.
- With respect to paragraph 187(2)(j) of the *Framework Regulations*, pressure/time plots and signal design should also be included.
- With respect to paragraph 187(2)(k) of the *Framework Regulations*, recording parameters, such as SP interval, station interval, sampling rate, recording filter(s) settings, gain control,

polarity, fold, aircraft elevation, etc., should be described. Also, any onboard processing should be identified.

c. Final Data Processing Report

With respect to subsection 187(3) of the *Framework Regulations*, the final data processing report describes the processes by which field data was manipulated to generate interpretable data displays. The following should be included as applicable to typical survey methods and equipment used as part of any GGE Program:

- With respect to paragraphs 187(2)(c) and 187(3)(a) of the *Framework Regulations,* an introduction and list of enclosures.
- For seismic reflection surveys:
    - each type of processing for which sections were generated, including the processing procedures applied to the data;
    - survey line list documenting lines that were processed;
    - final processed bin (grid) coordinates; and
    - final full fold survey outline coordinates.
- For gravity surveys:
    - all corrections applied;
    - method of correcting discrepancies at line intersections;
    - method of spatial filtering, residual mapping and second derivative mapping;
    - method of gravity modeling; and
    - loop closure maps for elevation control.
- For magnetic surveys:
    - all corrections applied to the total field data;
    - correction for diurnal;
    - correction with regional field;
    - method of spatial filtering, residual mapping and second derivative mapping;
    - method of correcting discrepancies at line intersections; and
    - method of magnetic modeling.
- For electromagnetic surveys:
    - all corrections applied to field and metadata;
    - all processing procedures applied to the final data; and
    - discussion of methods and processing for all 2D and 3D modeling and inversion.
- For surficial surveys such as bathymetric surveys, a discussion of methods and processing procedures applied to final surficial data.

d. Final Interpretation Report

With respect to subsection 187(4) of the *Framework Regulations*, the final interpretation report describes any understandings formed following assessment of the data. Additionally, if applicable, the interpretation of newly acquired data in an area should be referenced with respect to and correlated with any previously acquired data in the area, to expand upon current regional knowledge according to subsection 187(6) of the *Framework Regulations*.

For any GGE program that requires submission of a final interpretation report according to subsection 188(2) of the *Framework Regulations*, the following should be included:

- With respect to paragraphs 187(2)(c) and 187(4)(a) of the *Framework Regulations,* an introduction and list of enclosures.
- With respect to paragraphs 187(2)(e) and 187(4)(a) of the *Framework Regulations*, a description of all vessels or aircraft used for the program including the owner and for vessels, the flag of registry.
- For geophysical surveys:
  - description and illustration of all interpreted horizons;
  - details of corrections or adjustments applied to the geophysical data during interpretation;
  - any velocity information used for time-to-depth conversion;
  - description of any correlation between geophysical data and geological events;
  - correlated sections that adequately illustrate the interpretative technique for structural and stratigraphic interpretation;
  - informative figures such as seismic SP maps, gravity station maps, magnetic survey maps, CSEM source/receivers maps, track plots and flight lines with numbered fiducial points;
  - interpretative maps that are appropriate to the survey type such as:
    - for seismic reflection surveys: all maps displaying time structure, depth structure, isopach, isochron, velocity, seismic amplitude and character change;
    - for gravity surveys: all maps displaying Bouguer gravity, residual gravity field, derivative maps (if maps were not made, individual gravity profiles with sufficient annotation for interpretation);
    - for magnetic surveys: all maps displaying total magnetic intensity, corrected total field, residual magnetic field and derivative maps (if maps were not made, individual profiles with sufficient annotation for interpretation);
    - for electromagnetic surveys: MVO and PVO curves, 2D receiver line resistivity cross sections and 3D model resistivity cross sections and maps; and
    - Any other information, used or produced during the interpretation, such as bathymetry, synthetic seismograms, seismic modeling and attribute analyses, etc.
- For geological surveys:
  - description of the results of the project and how the results tie in to the regional geological framework;
  - any other information, such as bathymetry, used or produced during the interpretation of the data; and
  - figures should include:
    - location of cores, samples, or any other data used;
    - measured sections;
    - correlation or structural cross-sections;
    - core or sample descriptions;
    - micropaleontology and palynology; and
    - interpretative maps such as paleogeographic, facies and isopach.
- For geohazard surveys:

- list of items above pertaining to geophysical and geological (geoscientific) programs, as appropriate;
- a description of the surficial geology, including maps;
- results of side scan sonar surveys, including side scan mosaics;
- a description and discussion of the distribution and morphology of sedimentary units, pock marks, seabed photographs, seabed features such as sediment distribution, and, when appropriate, a discussion of ice scours, with an analysis of scour density, cross-sectional shape, depth of sediment disturbance and dimensions;
- descriptions of seabed photographs and their locations;
- location and description of samples and cores;
- results of any geotechnical investigations or other studies carried out during the survey;
- identification of man-made obstacles;
- a description of the features considered to be drilling hazards including a compilation map showing type, depth and extent of features; and
- any other information, such as bathymetry, used or produced during the interpretation of the data.

- For geotechnical programs:
  - location map of boreholes and any other data used;
  - a description of the boring and geotechnical equipment that was used during the program;
  - a description of sample handling procedures, storage, onboard measurements and results;
  - a description of the laboratory procedures, measurements and results;
  - correlations between borehole data and available geophysical data;
  - interpretative maps showing distribution and thickness of relevant geological/geotechnical units; and
  - any other information, such as bathymetry, used or produced during the interpretation of the data.
- For environmental programs:
  - a general overview of the data or samples that were acquired during the program and of any analyses that were performed on them;
  - a description of quality control and quality assurance procedures that were in place during the field program and, when appropriate, that were in place at facilities in which sample handling and analysis were performed; and
  - the results of any analyses that were performed on the data collected during the program.

Refer to subsection 188(2) of the *Framework Regulations* in instances in which the operator ceases to make the data available for purchase by the public, or the *Regulator* becomes aware that the data is not being made fully publicly available.

e. Acquired Data

With respect to subsection 187(5) of the *Framework Regulations*, data gathered as part of an approved program with fieldwork or obtained through an approved program without fieldwork are subject to the following submission requirements:

- All prescribed data formats are digital, when appropriate.
- All digital data should be submitted on USB, SFTP or other medium approved by the *Regulator* and be of reasonable resolution (e.g., 300 DPI minimum for TIFF images).
- All data to be submitted within 12 months of program completion.
- Any other materials produced as a result of studies may also require submission. Please confirm with the *Regulator* if this is the case for specific requirements.

Data submission requirements of GGE programs with fieldwork are survey specific and are presented in the tables in Appendix B for typical survey methods. If the survey methods applied are not presented in the tables, consult with the *Regulator* for advice. Tables are provided for the following:

- 2D Seismic Survey - Data Submission Requirements
- 3D Seismic Survey - Data Submission Requirements
- Geohazard Survey - Data Submission Requirements
- Controlled-Source Electromagnetic (CSEM) Survey - Data Submission Requirements
- Gravity/Magnetics Survey - Data Submission Requirements
- Geological Survey - Data Submission Requirements
- Geotechnical Program - Data Submission Requirements
- Environmental Program - Data Submission Requirements

In the case of programs without fieldwork (such as reprocessed or purchased data) the same criteria as presented in the tables in Appendix B should be followed for that particular survey type. In the cases of programs without fieldwork in which samples were borrowed from the *Regulator* or desktop studies were completed, consult with the *Regulator* regarding data submission requirements appropriate to the study. Additionally, the *Regulator* may request copies of other versions of data not specifically described in the tables provided in Appendix B.

With respect to section 57 of the *Framework Regulations*, the Operator should consult the *Regulator* if they plan to destroy, discard or remove any data, materials, samples or information from Canada.

Section 189 – Data Purchases

189 (1) A purchaser of data referred to in subsection 188(1) that were acquired in an area that is subject to an interest, as defined in section 47 (or 49) of the Act, must submit to the Board a final interpretation report that contains the documents and information referred to subsection 187(4), as applicable, if the costs of the purchase of the data are to be credited against a deposit or other costs in relation to the interest.

Reports from data purchaser

(2) If the purchaser has reprocessed or reinterpreted the data, and if the costs of the reprocessing or reinterpretation are to be credited against a deposit or other costs of the interest, the purchaser must submit to the Board, with the acquired data referred to in subsection 187(5), as applicable, a final data processing report that contains the documents and information referred to in subsection 187(3) and a final interpretation report that contains the documents and information referred to in subsection 187(4), as applicable.

Timing of submissions

(3) The reports and data required under subsections (1) and (2) must be submitted by the purchaser to the Board before the costs referred to in those subsections are credited.

Notice to Chief Conservation Officer

(4) A person who has submitted a report referred to in this section must, in respect of data that pertain to shotpoints or the location of stations, notify the Chief Conservation Officer, without delay, of any errors or omissions identified in or corrections made to the data after the report is submitted.

For information on release of data, refer to the following:

- In NL, refer to the *Disclosure of Digital Data and Information Policy.*
- In NS, contact the CNSOPB for information on data disclosure.

In respect of applications for allowable expenditure credit, in which an interest owner purchases, processes, re-processes or reinterprets geoscientific, geotechnical or environmental data and is seeking allowable expenditure for the associated costs, the interest owner must meet the requirements of subsections 187(2) – (6) of the *Framework* Regulations, as applicable. For further information:

- In NL, refer to the *Allowable Expenditure Credit Guideline.*
- In NS, contact the CNSOPB for information on allowable expenditure credits.

DRILLING AND PRODUCTION PROGRAMS

Section 190 – Reference

190 When submitting any information to the Board about a well, pool, zone or field under these Regulations, an operator must refer to each by the name given to it under section 59 or paragraph 60(b), as the case may be.

No guidance required at this time.

Section 191 – Results, Data, Analyses and Schematics

191 (1) An operator must ensure that a copy of the final results, data, analyses and schematics obtained from any well operation, including those obtained as a result of the following activities, is submitted to the Board:

(a) the testing, sampling and pressure measurements that are conducted as part of the field data acquisition program referred to in section 13 and the well data acquisition program referred to in section 18, as well as any evaluation, testing and sampling of formations that is conducted under section 62; and
(b) any verification conducted under paragraph 71(2)(a) and any segregation test conducted under paragraph 71(2)(b).

Period for submission

(2) Unless otherwise agreed to in writing by the Board, the operator must ensure that the copy is submitted within 60 days after the day on which any activity that gave rise to the results, data, analyses or schematics is concluded.

Refer to the *Data Acquisition Guideline.*

Section 192 – Survey

192 (1) An operator must ensure that a survey, certified by a person licensed under the Canada Lands Surveyors Act, is conducted to confirm the location of any well and production installation.

Copy of survey plan

(2) The operator must ensure that a copy of the survey plan is
(a) filed with the Canada Lands Survey Records; and .
(b) submitted to the Board.

- The requirements pertaining to well location surveys, and a description of the land division system are noted in the above legislation, with the following notes:
    - In the case of a subsea well, this refers to the location of the well at the SF, not the surface location of the RT on the installation.
    - For a platform well, the SF location is interpreted to be the location of the well at the wellhead deck level on the installation.
    - In the case of subsea templates containing several 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 Canada Lands Surveyor.
    - All surveys are to be referenced to NAD 27 and NAD 83 until the *Canada Oil and Gas Land Regulations* are updated from NAD 27 to NAD 83, at which time NAD 83 will suffice.
- The legal survey confirming position of the well should be submitted with the ADW referred to in section 17 of the *Framework Regulations* and the well history report referred to in paragraphs 199(1)(c) and (d) of the *Framework Regulations*, unless the well is suspended. For suspended wells, the legal survey should be submitted within 90 days of the date of suspension.
- The legal survey confirming the position of a production installation should be submitted as soon as the survey has been completed.

Section 193 – Critical Information (Drilling and Production)

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193 (1) The records that must be kept under section 181 include, in the case of an operation involving drilling or production, records containing the following information and documents:
(a) in respect of any assessment of the efficacy of a spill-treating agent under paragraph 11(4)(a),
> ***(i) a description of the assessment, including any oil samples used, and***
> ***(ii) a description of any tests conducted for the assessment and their results;***

(b) information concerning the inspection of any installation and its equipment or a pipeline for corrosion and erosion and any resulting maintenance activities carried out;
(c) the pressure, temperature and flow rate data obtained from compressors and from systems and equipment used for treatment and processing;
(d) information concerning the calibration of meters and other instruments on an installation;
(e) information concerning the testing of subsea, surface and subsurface safety valves;

(f) information concerning the status of each well and the status of well operations;

(g) in the case of a floating platform, information concerning all loads that could affect the motions, stability or inclination of the platform, including

> ***(i) data, observations, measurements and calculations related to its stability and station-keeping capability, including records of all of its movements,***
>
> ***(ii) the results of all tests and analyses conducted to assess its stability and station-keeping capability,***
>
> ***(iii) a description of every change in relation to its weight, its centre of gravity or the weight or distribution of temporary or portable equipment on it that may affect its stability, and***
>
> ***(iv) a description of the verification of the disconnect capability of any disconnectable mooring system;***

(h) in respect of boilers and pressure systems, the documents and information referred to in paragraphs 135(12)(d) to (f);

(i) information concerning each formation leak-off test and formation integrity test conducted under section 70;

(j) the findings resulting from the verifications of temporary safe refuges required under subsection 117(3); and

(k) the findings resulting from the verifications of the availability and condition of life-saving appliances required under subsection 119(11).

Retention periods

(2) The operator must retain the records referred to in subsection (1) for the following periods:

(a) in the case of the records referred to in paragraph (1)(a), for as long as the spill-treating agent is approved for use;

(b) in the case of the records referred to in paragraphs (1)(b) to (f), subparagraph (1)(g)(iv) and paragraphs (1)(i) to (k), five years after the day on which the record is created;

(c) in the case of the records referred to in subparagraphs (1)(g)(i) to (iii), for the life of the floating platform; and

(d) in the case of the records referred to in paragraph (1)(h), five years after the day on which the boiler or pressure system is taken out of service.

- Refer to the requirements and associated guidance for management and accessibility of records in Part 3 and section 48 of *Framework Regulations*.
- In addition to these requirements, refer to any specific requirements for records prescribed in the *Accord Acts* and the regulations and any condition of the *Regulator*. Attention should also be paid to provisions related to retention of records, provisions related to submitting records to the *Regulator* and the provisions related to offering up records to the *Regulator* before they are destroyed. Operators should ensure that the processes within their management system include these requirements.
- Specific requirements for provision of records to Officers are in the *Accord Acts* and requirements that prohibit these records from containing false or misleading information.

- It is not necessary that a single combined record be kept of the various topics listed above. 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.

Section 194 – Daily Production Record

194 (1) An operator must ensure that a daily production record is kept in respect of a field in which a pool or well is located until the field is abandoned and, at that time, must offer to submit the record to the Board before destroying it.

Contents

(2) The daily production record must contain, with respect to each day, the following information and documents:
(a) information concerning the calibration of meters and other instruments referred to in paragraph 193(1)(d);
(b) any measurements obtained under section 74;
(c) a description of the manner in which any fluids were disposed of, including through venting, burning or flaring, or transported for processing, whether through offloading or pipeline; and
(d) any other information relating to the production of petroleum and other fluids from each pool or well.

General

- 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.
- The daily production record should be in accordance with the flow allocation and flow calculation procedures approved under section 14 of the *Framework Regulations*.
- All volumes separated should be adjusted to standard conditions.
- The original recording of measurements used to determine the particulars should be included on the same record.
- A daily production record should be kept for each pool.

Content

The daily production record should contain the following:

- For production wells:
  - estimated oil, gas and water production (m^3/d) water/oil, gas/oil or gas/water ratios;
  - total number of hours well is in production;
  - average separator or treater pressure and temperature;

  - tubing head and subsurface pressure; and
  - in which 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.

- For injection wells:
  - estimated amount of gas, water, natural gas liquids, oil or other substances injected into the well;
  - the source from which the gas, water, natural gas liquids, oil or other substances were obtained;
  - tubing head pressure and temperature; and
  - the number of hours each substance was injected into the well.

- an estimate of total oil, gas and water production including the instantaneous flow rate, static pressure, differential pressure and flowing temperature taken at the same time each day;

- an estimate of total gas, water, natural gas liquids or other substance injected into the well including the instantaneous flow rate, static pressure, differential pressure and flowing temperature taken at the same time each day;

- particulars of the inventories and disposition of all production including the following:
  - open and closing oil in storage;
  - oil and gas volume transferred from the installation and the name of the tanker used to transport oil or gas;
  - gas used:
    - as fuel, and
    - for gas-lift operation;
  - oil, gas and acid gas flared; and
  - oil that is used as a hydraulic power fluid for artificial lift;

- if oil or gas is sold, the name of the purchaser or transporter;

- estimates should be provided for any produced fluids that were not measured, lost or spilled;

- details of calibration of meters and associated measurement equipment that is part of the approved flow system;

- for each approved meter, all information used to calculate a flow volume should be recorded and should incorporate all factors used in the approved flow calculation procedures. The information should include, if appropriate:
  - meter identification number;
  - instantaneous flow rate;
  - static pressure;

- differential pressure;
- flowing temperature;
- line size;
- orifice size;
- atmospheric pressure;
- basic orifice factor;
- real gas relative density factor;
- flowing temperature factor;
- Reynolds number factor;
- expansion factor;
- pressure base factor;
- temperature base factor;
- super compressibility factor;
- any other factors used;
- orifice flow constant;
- meter conversion factor;
- gas and liquid analyses and analysis date; and
- relative density.

- any flow parameter changes that could affect flow calculations should be noted. These include:
  - orifice change;
  - gas/liquid analyses update; and
  - changes to the database used in flow calculations.

- 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:
  - master terminal unit failure;
  - remote terminal unit failure;
  - communication failures;
  - low power warnings;
  - changes to database;
  - high/low differential pressure; and
  - over range values.

Section 195 – Formation Flow Test Records and Report

195 An operator must ensure that
(a) in respect of exploratory wells and delineation wells, a record of formation flow test results is submitted to the Board on a daily basis; and

(b) in respect of all wells, a formation flow test report is submitted to the Board as soon as the circumstances permit after each formation flow test.

General

- All reports submitted to the *Regulator* should be accurate, complete and provided in a searchable electronic format (e.g., PDF).
- All reports should be submitted to the C-NLOPB at information@cnlopb.ca or to the CNSOPB at info@cnsopb.ns.ca.
- All reports should either be submitted to the *Regulator* or made available electronically for download.
- All data accompanying the reports should be available in digital format as an Excel or ASCII formatted file.

Exploration and Delineation Wells

- Daily formation flow test reports should be submitted only while formation flow testing is being conducted.
- This report should either be submitted as part of the daily report under section 197 of the *Framework Regulations* or as a separate report. If separate reports are submitted, information need not be duplicated.
- These reports should include:
    - event history documenting the time of any action taken that may have affected the test or the interpretation of test results;
    - flow rate data corrected to standard conditions, noting correction factors and choke settings and the corresponding pressure/temperature data at the wellhead and at the test separator);
    - total volume of fluid recovery and the volumes associated with each fluid produced;
    - the amount of gas flared or vented or amount of oil burned;
    - all relevant data associated with the acquisition of fluid samples; and
    - at the conclusion of the test, a complete set of pressure/temperature data from all downhole gauges along with gauge specifics (e.g., make, model number, serial number, depth of measurement, date of calibration and the results of pre and post-test calibration checks). Preliminary submission of gauge data to the *Regulator* may be by email, or alternatively on USB, SFTP or other medium approved by the *Regulator*. The format for data submission should be columnar: real time (hh mm ss - 24 hr clock) not elapsed time, pressure (kPa absolute) and temperature (°C) separated by blank spaces, not commas.

Development Wells

Unless otherwise noted in the well approval or otherwise required by the *Regulator* (e.g., tests on secondary horizons or extendedformation flow tests[35] over targeted horizons), formation flow

[35] Extended formation flow tests are described in the *Accord Acts*

test reports associated with tests conducted on producers and injectors can be combined under one submission and submitted as part of the Annual Production Report required by section 202 of the *Framework Regulations*.

Section 196 – Pilot Scheme Report

196 (1) An operator must ensure that interim evaluations of a pilot scheme referred to in section 81 are reported to the Board in writing at the intervals referred to in paragraph 81(2)(b).

Report on completion

(2) On completion of the pilot scheme, the operator must ensure that a report is submitted to the Board that contains
(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.

No guidance required at this time.

Section 197 – Daily Reports

197 An operator must ensure that the following reports are submitted to the Board on a daily basis:
(a) a daily operations report that contains
> ***(i) a description of the works and activities that were carried out on the installation on the previous day and the current status of those works and activities,***
> ***(ii) a description of the works and activities that are expected to be carried out on the installation on the day on which the report is submitted,***
> ***(iii) a summary of the verification, inspection, monitoring, testing, maintenance and operating activities critical to safety that were carried out on the previous day,***
> ***(iv) a summary of the physical and environmental conditions that were observed under section 42 on the previous day,***
> ***(v) a summary of the information referred to in paragraph 193(1)(g) that was obtained on the previous day, and***
> ***(vi) any other information that is necessary to indicate the status of operations on the installation;***

(b) a daily drilling report that contains
> ***(i) the daily and cumulative costs of operating the installation,***
> ***(ii) all well and casing data obtained on the previous day,***

(iii) a description of the properties of the drilling fluid and all drilling fluid gas readings from the previous day,
(iv) a summary of any directional and deviation surveys carried out the previous day,
(v) a description of the formations encountered on the previous day,
(vi) the results of any blowout preventer test carried out on the previous day and the date of the most recent test, and
(vii) the results of any formation leak-off tests or formation integrity tests referred to in section 70 that were carried out the previous day;
(c) a daily geological report, consisting of well and field data acquired the previous day through the programs referred to in sections 13 and 18, geological assessments made the previous day and any other information that is relevant to those assessments; and
(d) in the case of a production installation, a daily production report that contains a summary of the information referred to in paragraphs 193(1)(a) to (c) in relation to the previous day and a summary of the daily production record referred to in section 194.

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a. General

- This section applies to all well operations (drilling, suspension, abandonment, completion, workover, well intervention or any other well operation) and production operations (producing, injecting, static, suspended) and to any activities being undertaken onboard an accommodations installation.
- Reports should be submitted as soon as the OA has been issued and continue until the OA has been suspended or the program has ended. This is inclusive of activities such as tow-out, installation, commissioning, decommissioning, etc.
- All reports submitted to the *Regulator* should be accurate, complete and provided in a searchable electronic format (e.g., PDF).
- All reports should be submitted to the C-NLOPB at information@cnlopb.ca or to the CNSOPB at info@cnsopb.ns.ca.
- All reports should either be submitted to the *Regulator* or made available electronically for download.
- All data accompanying the reports should be available in digital format.

b. Daily Operations Report

With respect to paragraph 197(a) of the *Framework Regulations*, regardless of the type of installation, a Daily Operations Report must be submitted. This report need not be submitted separately if the information is already included in the daily drilling report and the daily production report submitted pursuant to paragraphs 197(b) and (d) of the *Framework Regulations*, respectively. Other details that should be included are as follows:

- With respect to subparagraph 197(a)(i) of the *Framework Regulations*, the current status of activities on the installation should be reported as of 06:00 hours.

- With respect to paragraph 197(a)(iii) of the *Framework Regulations*, this should include the status of equipment and systems critical to safety and protection of the environment, including a list of any inhibits or impairments.
- With respect to paragraph 197(a)(iv) of the *Framework Regulations*, this should include maximum and minimum significant sea states, maximum and minimum temperature, current, maximum and minimum winds, ice, snow, fog, etc.
- With respect to paragraph 197(a)(v) of the *Framework Regulations*, for floating platforms, this should include the maximum to minimum range of all measurements related to stability and station keeping capability of the installation experienced throughout the day (e.g., pitch, heave, roll, anchor/mooring line tensions, DP).
- With respect to paragraph 197(a)(vi) of the *Framework Regulations*, the "other information" should include the following:
    - The number of persons onboard by employer.
    - The names of persons in key positions (e.g., OIM, Captain, Production Supervisor, Maintenance Supervisor).
    - Location and duty of support craft, including number of helicopter flights and number of POB transported by helicopter or vessel.
    - Occurrence of any emergency drill or exercise.
    - Occurrence of any workplace committee meeting.
    - Occurrence of any incident.
    - Occurrence of any inspection or audit.
    - Quantities of key consumables onboard.

c. Daily Drilling Report

With respect to paragraph 197(b) of the *Framework Regulations*, the daily drilling report should be submitted for any associated well operations that are undertaken and should include the following additional information pursuant to paragraphs 197(a)(i) and (vi) of the *Framework Regulations*, as applicable:

- Pressure tests or function tests of all well control equipment, including any used in intervention activities.
- Pressure tests of casing.
- Cement data, including:
    - summary of the cement job and whether any lost returns occurred; and
    - the estimated top of cement, including the basis for this estimate.
- Tubing data.
- Associated data and sizes of the bottom hole drilling assembly, including bits.
- Slip and cut data for the drilling line.
- Summary of any other parameter as described in the well approval.

d. Daily Geological Reports

With respect to paragraph 197(c) of the *Framework Regulations*, the daily geological reports should include the following:

- Lithological and hydrocarbon show description for all cuttings.
- A table representing the drilled geological formations/intervals identifying the prognosed tops, as drilled tops (referencing determination method, i.e., whether from cuttings or logs), and the difference (in metres) between the two.
- Drilling fluid gas readings detailing total hydrocarbon gas content and chromatographic breakdown.
- A record of the chemical and physical properties of the drilling fluid.
- A mud log which includes the following tracks:
    - Rate of Penetration, LWD Gamma Ray, Caliper
    - Depth
    - Cuttings - Oil Show
    - Drilling Fluid - Total Gas Units
    - Drilling Fluid - Chromatographic Analysis
    - Lithology (Graphic)
    - Lithology Description and Remarks
    - Other LWD data – Resistivity, Sonic and Neutron-Density, as acquired
    - The scale of the log should be 1:1000 or 1:500
- The mud log may be segmented to reflect the hole section being drilled and it should clearly indicate on this log the probable source of any gas that is more than background levels.
- When conventional core is acquired, any description available from the ends of core barrels should be captured in the daily report according to standard cuttings description.
- A summary of any other parameter as described in the FDAP or WDAP submitted in accordance with the requirements and associated guidance for sections 13 and 18 of the *Framework Regulations*.
- The following logs and reports should be submitted:
    - All formation evaluation logs, as acquired.
    - Updated directional survey.
    - Pressure-depth surveys when acquired.

Access to the daily geological reports should be provided to the *Regulator* via well monitoring web portals, or through email from the operator if web portals are unavailable. Updates to logs and surveys acquired in a well should be submitted to the *Regulator* in the formats specified in section 7.2 of the *Data Acquisition Guideline.*

e. Daily Production Reports

With respect to paragraph 197(d) of the *Framework Regulations*, the daily production report should include the following additional information pursuant to subparagraphs 197(a)(i) and (vi) of the *Framework Regulations:*

- The status of each well, including pressure, temperature and flow rate.
- The quantity of oil and gas produced, stored or transported. If tankers were used, the name of the tanker should be included.

- The maximum and average oil-in-water measurements from discharges during the reporting period.

With respect to summary of the daily production record referred to in section 194 of the *Framework Regulations* and other details, the operator should consult with the *Regulator* regarding the level of detail to be included and the format of the submission.

Section 198 – Monthly Production Report

198 An operator must ensure that a report summarizing the production data collected during a given month is submitted to the Board not later than the 15th day of the subsequent month.

- In NL, refer to the *Monthly Production Reporting Guideline.*
- In NS, the operator should contact the CNSOPB for information on the submission format of the monthly production report.

Section 199 – Well Records and Reports

199 (1) An operator must ensure that
(a) a well termination record is submitted to the Board in respect of a well within 21 days after
(i) the day on which the well is abandoned,
(ii) the day on which the well is suspended if the suspension is planned to be for a period that is longer than 21 days, or
(iii) the day on which the well is completed or recompleted;
(b) a well operation report is submitted to the Board in respect of a well that requires a workover or intervention within 30 days after the day on which the workover or intervention is completed;
(c) a well history report is submitted to the Board in respect of a development well within 45 days after the day referred to in subparagraph (a)(i), (ii) or (iii), as the case may be;
(d) a well history report is submitted to the Board in respect of an exploration or delineation well within 90 days after the day referred to in subparagraph (a)(i), (ii) or (iii), as the case may be; and
(e) the actual cost breakdown of all well operations is submitted to the Board within 90 days after the day on which a well is abandoned, suspended or completed.

Well termination record – contents

(2) The record required under paragraph (1)(a) must describe the manner in which the well has been abandoned, suspended, completed or recompleted and must include a schematic of the

well illustrating the nature and location of the plugs used to abandon or suspend the well or the equipment used to complete or recomplete the well.
Reports - contents

(3) The reports required under paragraphs (1)(b) to (d) must contain a record of all operational, engineering, petrophysical, geophysical and geological information that is relevant to the well operation, including any problems encountered during the well operation and the results of any formation leak-off test or formation integrity test conducted under section 70.

Impact description

(4) The report required under paragraph (1)(b) must describe any impact of the workover or intervention on the performance of the well, including any effect on productivity, injectivity and the recovery of petroleum.

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a. General

- All reports submitted to the *Regulator* should be accurate, complete and provided in a searchable electronic format (e.g., PDF) or as noted below.
- All reports should be submitted to the C-NLOPB at information@cnlopb.ca or to the CNSOPB at info@cnsopb.ns.ca.
- All reports should either be submitted to the *Regulator* or made available electronically for download.
- With respect to wells, the following interpretation is provided:
  - **Well termination date** – means the date on which a well has been abandoned, completed or suspended as defined in the *Accord Acts*.[36]
  - **Abandoned** – in relation to a well, means a well or part of a well that has been permanently abandoned.
  - **Suspended** – in relation to a well, means a well or part of a well for which production or well operations have temporarily ceased.
  - **Completed** – in relation to a well, means a well that is prepared for production or injection operations.
- All logs, surveys, analyses and reports relevant to evaluation programs conducted in support of a FDAP or WDAP should accompany the well reports referenced in this section as appendices or be submitted upon their completion.
- When secondary reports are generated, either by the operator or by third parties resulting from analysis of well data and relevant to the information required, these reports should be submitted to the *Regulator* with an accompanying cover letter.
- With respect to subparagraph 199(1)(a)(ii) of the *Framework Regulations*, short-term suspensions could result from equipment maintenance or repair, physical and environmental conditions, ice or other reason even if the drilling installation is released from the well site.

[36] C-NLAAIA 76(5); CNSOPRAIA 79(5)

In addition, in certain situations the installation may have to be moved to sheltered waters to enact repairs or to avoid extreme physical and environmental conditions, including ice, or the installation may have to complete work on another well in the interim for various reasons.

b. All Well Reports – General Requirements

The well termination record, well operation report and well history report, in general, should include the following information:

- Although operators may have their own well names, with respect to submitting information to the *Regulator*, pursuant to section 190 of the *Framework Regulations*, the assigned name for the well must be included in the title of the report.
- The name of the installation.
- A summary of the nature and purpose of the well.
- The coordinates of the well (NAD 27 and NAD 83).
- The spud date of the well.
- The RT (or KB) elevation (relative to MSL, tide corrected, in the case of an offshore well).
- The water depth (in the case of an offshore well).
- The total depth of the well (MD and TVD).
- The date drilling was completed (date and hour total depth was reached).
- The status of the well termination (i.e., suspended, abandoned, or completed).
- The well termination date (e.g., the date that the installation last completed operations on the well).
- The operator's representative responsible for the accuracy and completeness of the report should sign and date each report submitted.

Other considerations are as follows:

- Electronic reports should be submitted as searchable PDF files submitted on USB, SFTP or other medium approved by the *Regulator*. Digital data related to cores, logs, surveys and analyses conducted should be submitted in the format as requested below.
- Measurements should be given using the S.I. (System International) system.
- Dates and times should be given as year/month/day/hour.

c. Well Termination Record

With respect to paragraph 199(1)(a) and subsection 199(2) of the *Framework Regulations*, in the event a well is altered, an updated well termination record and new schematic should be supplied to the *Regulator*.

d. Well Operation Report

With respect to paragraph 199(1)(b) and subsections 199(3) and (4) of the *Framework Regulations*, the well operations report should include:

- a summary of the well operation, including any problems encountered;
- an updated well termination record identifying all changes made as a result of the well operation along with any updates to the perforated or completed intervals;
- a description of the completion fluid properties;
- a schematic of, and relevant engineering data on, the down-hole equipment, tubulars, christmas tree and production control system; and
- details of any impact of the well operation on the performance of the well, including any effect on recovery.

e. Well History Report

With respect to paragraphs 199(1)(c) and (d) and subsection 196(3) of the *Framework Regulations*, the well history report should include:

- a summary of operations on the well including a summary of any problems encountered and the steps taken to overcome the problems. The total time delay associated with each problem and a summary of any non-productive time including due to physical and environmental conditions, pack ice, or icebergs should be included;
- 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 DHSVs);
- hole sizes and depths;
- bit records according to IADC/CAOEC codes and formats;
- detailed casing, tubing and pipe tallies including hangers and seals;
- 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;
- information in respect of the primary cement job of all casing strings and liners including the use of centralizers and scratchers, flushes and spacers, amount used, composition, slurry density, volume pumped and the estimated top of cement behind the casing string or liner (and the basis of the estimate (e.g., calculated, cement evaluation log));
- information respecting the success or otherwise of the primary cement job and the details respecting any remedial cement squeeze, top-up job, etc.;
- the type of drilling fluid and summary of the properties maintained for each phase of the hole;
- if OBF was used, the total quantity of OBF consumed during drilling;
- the total amount of mud-derived oil discharged with cuttings and 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);
- a summary and description of any drilling fluid losses;

- details of any fluid disposal downhole, including volumes, rates, pressures, dates, nature of the fluid;
- details of any kicks encountered including volumes, pressures and a summary of associated well control operations;
- a time distribution breakdown of each activity on the well from the hour the installation arrived on location to the time the rig was released, showing the total hours for each type of operation;
- FLOT or FIT 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;
- 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; and
- a summary of the data and information collected as part of a WDAP.

An update should be provided to the Well History Report anytime there is a material change to the status of the well or a change to any change to equipment installed in 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 referred to in paragraph 199(1)(b) of the *Framework Regulations*.

In submitting information pertinent to well evaluation programs, the operator should adhere to the following format:

f. Geology

- **Drill Cuttings**

  The prescribed frequency of sampling, and the intervals over which samples were not obtained should be indicated. The distribution of samples and the location of stored suites of cuttings should be stated.

  Additionally, the following should be submitted at this time, if applicable:

  - Digital colour photos of washed and dried cuttings samples for exploration and delineation wells. The digital colour photos should be taken under white and ultraviolet light and identify the well-bore name, depth interval and scale.
  - Any separate petrographic, biostratigraphic or geochemical reports produced relating to samples collected. If no such reports are produced, a statement to this effect should be included.

In addition to the electronic copy requirements noted above, operators should submit on USB, SFTP or other medium approved by the *Regulator*, one digital copy of data for the following data types:

- Digital prints of cuttings photographs in JPEG, PNG or TIFF format at a minimum resolution of 300 DPI.
- Datasets related to reports conducted using cutting samples in ASCII format (e.g., petrographic, geochemical, XRD).

- **Conventional and Sidewall Cores**

  - **Conventional Core**
    A table showing the core number, interval and amount of recovery. The storage location of conventional core should be indicated.

  - **Sidewall Core**
    A table showing for each coring run, the depths sampled and results achieved (e.g., recovery, misfires). When applicable, the type of analyses preformed on each sample, and whether the sample was tested to destruction should be stated. The storage location for any remaining sidewall core should be indicated.

  Digital colour photos should be provided for conventional and sidewall core for all wells, taken immediately after slabbing. The digital colour photos should be taken under white and ultraviolet light and identify the well-bore name, core number, depth interval and scale.

  Any separate core analysis reports (routine and special), including any reports of core photographs related to samples collected, should be provided upon completion.Guidance on these reports is provided in section 7.2.2 of the *Data Acquisition Guideline*.

- **Lithology**

  A lithological description of all cuttings and cores (including sidewall and conventional cores) with depth, including a description of any visual shows of hydrocarbons as seen under either conventional or fluorescent light, should be included. An appraisal of secondary horizons should be included to address intentions of possible future testing.

  - **Stratigraphic Column**
    A summary table/chart of formations or biostratigraphic units should be provided showing name, age, lithology, palaeontology, depth, sub-sea elevation and thickness of each stratigraphic unit penetrated.

  - **Biostratigraphic Data**
    A chart should be included summarizing the biostratigraphic data (palynology, micropaleontology) with reference to the lithostratigraphic picks in the well.

Any separate petrographic, biostratigraphic or geochemical reports produced relating to samples collected should be provided upon their completion. If no such reports are produced, a statement to this effect should be included.

g. Well Evaluation

- **Directional and Deviation Survey**
  A plan view should be included showing the location of the borehole with respect to the wellhead for any well that deviated more than 10° from the vertical over any part of the hole. Bottom-hole coordinates referenced to surface location should be provided for all wells. The final survey should be submitted in XLS format.

- **Mud Log and Drilling Fluid Report**
  The final mud log and details of the drilling fluid are provided according to guidance in section 197 of the *Framework Regulations.*

- **Downhole Logs & Surveys**
  A list/table should be provided showing all logs and surveys run in the well noting the date, run number, type, interval and service company. Electronic copies and digital data of final logs not submitted previously should be submitted at this time according to guidance provided in the *Data Acquisition Guideline.*

- **Completion Records and Formation Stimulation (if applicable)**
  The following should be included:
  - A copy of the completion record for development wells noting the interval(s) perforated and a schematic of the equipment installed on the well when it directly affects well production or well evaluation.
  - A copy of any report respecting well stimulation including the date of stimulation, intervals, method, contractor, stimulants, amounts and results.

- **Formation Flow Test Results**
  The operator of an exploration or delineation well should provide in the well history report a brief summary of the results and any reports associated with any formation flow test(s) conducted.

  The following should be included:
  - The date, test number and interval tested.
  - The method of obtaining pressures and results should be presented noting the rate of oil, gas and water production, gravity of oil and gas at standard conditions, water salinity in NaCl equivalent, and formation temperature and pressure.

  Additionally, the operator is required to submit, in accordance with the requirements for the well history report, copies of:

  - Reports submitted to the operator by service companies and consultants, when applicable, relevant to the conduct of formation flow tests conducted.
  - Any fluid analysis reports of oil or condensate, gas and water samples collected at surface facilities or by downhole sampling methods.

  Results of formation flow tests conducted on development wells covered under the standard test program detailed under section 63 of this Guideline should be documented as part of the Annual Production Report submitted for the field.

- **Fluid Sampling**
  A summary should be provided of all fluid samples collected noting the fluid sampling stations, date, depth and method of acquisition. The analysis of all fluid samples must also be provided. With respect to submission of samples and analysis, refer to guidance in section 7.2.3 of the *Data Acquisition Guideline.*

- **Geophysical Surveys**
  The following information should be included in the well history report:

  - The final report of check shot surveys, including:
    - recording parameters;
    - summary of field data, corrections applied;
    - time/depth report;
    - calibrated sonic log;
    - corrected well seismic log; and
    - synthetic seismogram(s) displayed to match the operator’s most recent seismic data near the well.
  - The final report(s) associated with VSP surveys, including:
    - displays of the downgoing and upgoing waves, before and post processing, displayed at the same scale as the operator's seismic data near the well;
    - a description of the processing sequence applied to the data; and
    - any composite logs produced.
  - With respect to submission of geophysical survey data, refer to guidance in section 7.2.1 of the *Data Acquisition Guideline.*

h. Submission of Other Data and Analysis

The following should also be provided as part of the well history report, if not submitted previously:

- Petrological reports
- Paleontological reports
- Petrographic reports
- Biostratigraphic reports
- Palynological reports
- Geochemical reports

- Age determinations (e.g., K/Ar)
- Reservoir engineering data on cores and cuttings, including the data and results of all routine and special core analysis studies
- Photographic record of core under natural and ultraviolet light
- Mud Loggers Report
- Drilling Fluid Report Form
- Directional and deviation surveys
- Logs requiring secondary processing
- Details of formation flow testing for exploration or delineation wells
- Oil, gas and water analyses
- Completion data such as tubing and stimulation records.
- Composite well records
- Final survey plan

i. Type of Well Termination

The following information should be included with respect to the type of well termination:

Well Status	Remarks
Suspended	In the case of a well that is suspended, the Well History Report should contain information respecting the condition of the well in sufficient detail to be able to properly plan a program to re-enter the well and conduct subsequent well operations. This should include: • a list of any completed or perforated intervals and associated locations in the well; • the estimated length and depth of any cement plug placed in the well and the recipe of the cement slurry, the volume pumped and whether the plug was felt or otherwise confirmed to be in place; • 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 well-bore; • 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; • 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 reentry; • details of the wellhead including the type of wellhead, pressure rating, status and any other relevant information; • in the case in which the well is suspended with either a BOP stack or Christmas tree installed, details of the status of this equipment;

<table>
<tr><th>Well Status</th><th>Remarks</th></tr>
<tr><td></td><td>when applicable, the location and status of beacons or other equipment to assist with re-entry operations; and
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 or to permanently plug and abandon the well. These plans may be provided to the Regulator separately from the Well History Report.</td></tr>
<tr><td>Abandoned</td><td>In the case of a well that has been plugged and abandoned, the Well History Report should include a detailed record respecting the various plugs and other barriers that are in the well to ensure well-bore security and the prevention of the uncontrolled flow of hydrocarbons from the well. This should include:
a list of any completed or perforated intervals and associated locations in the well;
the information described above for suspended wells to the extent applicable;
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 or mechanical plugs;
in the case in which an annulus may have been open to a formation, the manner in which the annulus has been plugged and abandoned;
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 SF and the reasons that made it impractical to recover the equipment; and
in the case of the offshore well, the results of any seabed clearance survey conducted with an ROV or other equipment.
Operators should be aware that they are responsible for well-bore 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.</td></tr>
<tr><td>Completed</td><td>In the case of a well that has been completed, 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. This should include:
the depths of all perforated or completed intervals;</td></tr>
</table>

Well Status	Remarks
	• 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; • details of the tubing string including OD, ID, drift diameter, weight, grade and any pressure tests performed in respect of the tubing; • information respecting any DHSV or ASV including the type of valve, its depth in the tubing string and the results of any pressure test, function test or inflow test performed following the installation of the valve; • 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 • details respecting the wellhead, and the Christmas tree equipment (and control system) including the vendor, the rated working pressure and schematic of the equipment.

j. Release of Data

- With respect to the release of data and physical samples:
  - Information and documentation on wells will be made available in accordance with the *Accord Acts*[37] and in accordance with how the well has been classified by the *Regulator* pursuant to section 59 of the *Framework Regulations*. Information and documentation on wells will be made available as follows:
    - In NL, data will be made available via the **Data and Information Hub** on C-NLOPB's website or by contacting information@cnlopb.ca.
    - In NL, physical samples are available for viewing at the CSRC.
    - In NS, refer to the directory of wells on CNSOPB's website. Data and physical samples can be viewed by contacting CNSOPB.
  - In NL, additional guidance on release of data, including well data, is provided in the *Disclosure of Digital Data and Information Policy*.
  - In NS, contact the CNSOPB for guidance on release of data.
  - When a delineation well has an exploratory component targeting a previously undrilled horizon, the *Regulator* may classify parts of the well as exploratory resulting in a change to the privilege period for the well data.
  - When a development well has an exploration or delineation component, the *Regulator* may classify parts of the well as exploratory or delineation resulting in a change to the privilege period for the well data.

[37] C-NLAAIA 119(5); CNSOPRAIA 122(5)

Section 200 – Environmental Report – Exploration or Delineation Drilling

200 An operator must ensure, in relation to a drilling program that involves an exploratory well or a delineation well, that an environmental report that contains the following documents and information is submitted to the Board within 90 days after the day referred to in subparagraph 199(1)(a)(i), (ii) or (iii), as the case may be:
(a) a summary of the physical and environmental conditions under which the drilling program was conducted and, if applicable, a description of ice management activities and non-productive time caused by meteorological or ice conditions;
(b) a summary of the environmental protection measures in place during the drilling program, the measures taken to mitigate the effects of any reportable incident, the effectiveness of those measures and any adjustments made for their continued improvement;
(c) a summary of the performance of the drilling program in relation to the environment, including in relation to the objective of reducing environmental risks;
(d) a summary of any emergency response drills and exercises for the protection of the environment that were completed; and
(e) all wildlife observation data that was required to be recorded under paragraph 181(1)(e).

- This section applies to any activities that are conducted under an exploration or delineation drilling program that are being conducted separately from a production project and may include construction, diving, geoscientific, geotechnical or environmental activity associated with that program. For submission of environmental reports in relation to a production project refer to section 201 of the *Framework Regulations* and for separate geoscientific, geotechnical or environmental programs refer to section 186 of the *Framework Regulations*.
- These reports should also consider any conditions or commitments on observation or reporting from associated Environmental Assessments and Impact Assessments.
- All reports submitted to the *Regulator* should be accurate, complete and provided in a searchable electronic format (e.g., PDF).
- All reports should be submitted to the C-NLOPB at information@cnlopb.ca or to the CNSOPB at info@cnsopb.ns.ca.
- All reports should either be submitted to the *Regulator* or made available electronically for download.
- With respect to paragraph 200(a) of the *Framework Regulations*, the report should include a summary of the physical and environmental conditions relevant to the safe and environmentally responsible conduct of the activity. The raw physical and environmental data collected during the program should be provided in digital format.
- With respect to paragraphs 200(b) and (c) of the *Framework Regulations*, this should include a summary of:
  - all environmental incidents, the results of the root cause analysis of each incident and associated follow-up and corrective actions;

  - all discharges and emissions and their ultimate fate including efforts to reduce waste discharges or to reduce the effects individual wastes may have in the receiving environment;
  - each chemical used in the past year, including the hazard rating, quantity used, and its ultimate fate;
  - identifiable common issues or trends from all leading and lagging indicators associated with environmental protection and performance; and
  - continuous improvement of environmental management systems and associated environmental performance.
- With respect to paragraph 200(d) of the *Framework Regulations*, this should include a summary of spill contingency planning exercises or any other environmental contingency planning exercises. The summary for each exercise should include the exercise scenario, participants, the goal of the exercise, lessons learned and resulting changes to contingency plans.
- With respect to paragraph 200(e) of the *Framework Regulations*, wildlife observation data should include birds, mammals, sea turtles, etc., including their condition upon observation and any action taken.

Section 201 – Annual Environmental Report – Production and Pipeline Projects

201 An operator must ensure, in relation to a production project or pipeline project, that an environmental report that contains the following documents and information with respect to a given calendar year is submitted to the Board not later than March 31 of the subsequent year:
(a) a summary of the general physical and environmental conditions to which each operations site was subjected;
(b) a description of any ice management activities carried out;
(c) a summary of the environmental protection measures in place, the measures taken to mitigate the effects of any reportable incident, the effectiveness of those measures and any adjustments made for their continued improvement;
(d) a summary of the performance of the project in relation to the environment, including in relation to the objective of reducing environmental risks;
(e) a summary of any emergency response drills and exercises for the protection of the environment that were completed; and
(f) all wildlife observation data that were required to be recorded under paragraph 181(1)(e).

- This section applies to any activities that are conducted under a production project and includes any drilling, diving, construction, geoscientific or environmental activities associated with that project. For submission of environmental reports in relation to a separate exploration or delineation drilling program refer to section 200 of the *Framework Regulations* and for separate geoscientific, geotechnical or environmental programs refer to section 186 of the *Framework Regulations*.

- These reports should also consider any conditions or commitments for observation or reporting from associated *Development Plans* and Environmental Assessments and Impact Assessments.
- All reports submitted to the *Regulator* should be accurate, complete and provided in a searchable electronic format (e.g., PDF).
- All reports should be submitted to the C-NLOPB at information@cnlopb.ca or to the CNSOPB at info@cnsopb.ns.ca.
- All reports should either be submitted to the *Regulator* or made available electronically for download.
- With respect to paragraph 201(a) of the *Framework Regulations*, the report should include a summary of the physical and environmental conditions relevant to the safe and environmentally responsible conduct of the activity. The raw physical and environmental data collected during the program should be provided in digital format.
- With respect to paragraphs 201(b) and (c) of the *Framework Regulations*, this should include a summary of:
  - all environmental incidents, the results of the root cause analysis of each incident and associated follow-up and corrective actions;
  - all discharges and emissions and their ultimate fate including efforts to reduce waste discharges or to reduce the effects individual wastes may have in the receiving environment;
  - each chemical used in the past year, including the hazard rating, quantity used, and its ultimate fate;
  - identifiable common issues or trends from all leading and lagging indicators associated with environmental protection and performance; and
  - continuous improvement of environmental management systems and associated environmental performance. This should also 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).
- With respect to paragraph 201(d) of the *Framework Regulations*, this should include a summary of spill contingency planning exercises or any other environmental contingency planning exercises. The summary for each exercise should include the exercise scenario, participants, goal of the exercise, lessons learned and resulting changes to contingency plans.
- With respect to paragraph 201(e) of the *Framework Regulations*, wildlife observation data should include birds, mammals, sea turtles, etc., including their condition upon observation and any action taken.

Section 202 – Annual Production Report

202 An operator must 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 that contains information on how the operator manages and intends to manage the resource being produced without waste, including

(a) for the preceding calendar year, details on performance, production forecasts, reserve revision, the reasons for deviations in well performance from forecasts in previous annual production reports, gas conservation resources, efforts to maximize the recovery of petroleum and operating and capital expenditures, including the cost of each well operation; and
(b) for the preceding calendar year, the current calendar year and the next two calendar years, capital costs and fixed operating costs for each well and field in a production project, variable costs, commodity prices and financial commitments in relation to the transportation of the resource, including by pipeline.

General

- The purpose of this 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 section 79 of *the Framework Regulations*.
- The report covers the preceding calendar year between January 1 to December 31 inclusive.
- All reports submitted to the *Regulator* should be accurate, complete and provided in a searchable electronic format (e.g., PDF).
- All reports should be submitted to the C-NLOPB at information@cnlopb.ca or to the CNSOPB at info@cnsopb.ns.ca.
- All reports should either be submitted to the *Regulator* or made available electronically for download.

Content

The annual production report should provide an update to the Resource Management Plan as specified in the *Development Plan*. The *Development Plan* establishes a basis for the resource management of a field or a pool. 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 Oilfield Practices* and economics principles. 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). The Resource Management Plan is valid for the life of a pool or field and should be modified as new information is acquired and therefore the update to the Resource Management Plan should be based on the latest geological, geophysical, petrophysical and reservoir information. The update can reference other areas of the report but should highlight the changes to the Resource Management Plan.

The report should include the following information:

- **Geology and Geophysics**
  Any changes in geological data/models, methods or interpretations should be presented or referenced. This should include the impact of drilling, production or other work on the geologic or reservoir model, and the revised structure map showing well locations and fluid contacts. Each reservoir sub-unit should be illustrated by isopach maps of gross and net pay, an isoporosity map and a hydrocarbon pore volume map.

- **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. This should include but not be limited to:
  - a summary of results of PVT studies conducted indicating the pool from which samples were acquired and status of submissions made to the *Regulator*;
  - changes in composition of fluids produced from the pool;
  - changes in composition of injected fluids, compatibility studies, injectivity and pulse tests;
  - changes in reservoir pressures, temperatures and pressure/depth plots;
  - discussion of sweep efficiency including maps showing the estimated location of displacing fluid fronts;
  - studies to assess pool performance;
  - a review of water or sand production for each pool, highlighting wells that have experienced water breakthrough or sand production, the likely source of the water or sand and a discussion of the efforts to reduce water or sand production;
  - 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; and
  - a summary of the results of any studies conducted to assess infill well potential or to investigate methods to improve recovery.

- **Reserve Estimates**
  Any updates to estimates of reserves should be provided for each pool or hydrocarbon-bearing reservoir. This should include a table providing the oil and gas in place, recoverable reserves and recovery efficiency with a discussion of changes with respect to the approved *Development Plan* or previous reserves update.

- **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. Any updates with respect to performance of each well and alterations to production equipment for the pool or field, including:
  - verification of the well integrity (e.g., condition of well barriers and current status) of all active and suspended wells;
  - the date and type of any well treatment or workover and a discussion of the effect of such measures on well performance behaviour;
  - a tentative schedule for drilling production, injection, disposal or observation wells;
  - 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; and
  - a review of SSV performance including, for each of the SSV tests, the date of the test, the differential pressure, closure times, the results of the test and the time interval between tests.

- **Production and Export Systems**
  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.

  Any updates to production and export systems should also be provided.

- **Organization Chart**
  An updated organization chart showing the reporting relationships of persons involved in implementing the resource management plan should be included.

- **Development and Operating Cost Data**
  Updates to operating and capital expenditures should be provided, including the cost of each well operation, for the preceding year, the current-year prediction and the projections for the next two years, including:
  - 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;
  - 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
  - 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;
    - routine maintenance of systems and equipment;
    - upgrades and de-bottlenecks of systems and equipment;
    - major modifications for third parties; and
    - any other expenditures outside these categories; and

- an explanation of any large variations from previous annual reports

In addition to the update to the Resource Management Plan, the annual production report should 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. As such, the report should also contain the following information:

- A review and summary of production activities and performance of the wells, zones, pools and field(s) during the reporting period, including:
  a) tables of production from, and injection into, a pool or field(s), including
     i) the operating 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) a review of production from, and injection into, each well that is in the pool or field, including the following:
     i) a brief discussion highlighting wells that have experienced a significant change in production and injection performance and the likely reasons for the change;
     ii) a table showing changes in well status (e.g., producer, injector, suspended or abandoned, perforated intervals, artificial lift installation); and
     iii) 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; and
        - 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.
  c) 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 capability; and predicted performance based on reservoir simulation studies and the measures that have been implemented or planned to improve or sustain production;
  d) location of fluid interfaces should be examined to identify potential bypassed petroleum and locations in which infill drilling may be justified;
  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) the details of pool performance including a discussion of the performance of each pool with reference to the tables in paragraph (a) with particulars as follows:
     i) calculations of the voidage replacement on a monthly and cumulative basis for each pool and each pattern or segment; and
     ii) pool pressure performance discussion;

g) 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 or acid gas that is flared and vented;
   iii) a listing of cased hole logs run including on which wells and the date; and
   iv) formation flow test reports associated with tests conducted on producers and injectors (unless otherwise noted in the approval issued for an ADW); and
h) upon request, a report that forecasts system deliverability and 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 years.

Annual Pool Pressure Survey Report

The operator will be required to conduct an annual pool pressure survey for the field. The results for the annual pool pressure survey(s) should be submitted to the *Regulator* as part of the annual production report. The submission should contain an analysis of reported pressures, an isobaric map of these pressures corrected to datum depth, the proposed program for the upcoming year reflecting on the strategy described in the FDAP and the wells surveyed in the previous year(s). The proposed program should include:

- the planned survey date;
- each pool's datum depth;
- a list of the wells or alternates to be included in the survey;
- the type of survey planned for each well (static gradient, build-up or fall-off survey) including the shut-in time before conducting the survey; and
- the details of instrumentation used in the survey, including gauge calibration details.

When required, the following equation should be used by the operator when correcting run depth pressures to datum depth:

$$Pd = Pr + Grf\ (Dd - Dr)$$

Pd = gauge pressure at datum depth, kPag
Pr = gauge pressure at run depth, kPag
Grf = well-bore fluid gradient, kPa/m
Dd = datum depth, metres
Dr = run depth, metres

Use of the above equation is required when:

- the distance separating run depth and datum depth is relatively small;
- oil is present in the well-bore to a depth up to, or shallower than, run depth; or
- the gradient of the well-bore column is the same as the reservoir gradient (i.e., flowing pressure for the interval has not fallen below the bubble point pressure for reservoir oil or the dew point pressure for reservoir gas).

When the fluid gradient in the well-bore is different from the reservoir fluid gradient, the following two-step extrapolation procedure is required:

- using the well-bore gradient as obtained from a static gradient survey, calculate the pressure to the mid-point of the producing interval if the interval thickness is small, or to the top or base of the interval if it is large; then
- using the reservoir gradient, extrapolate the pressure calculated above to the datum depth, with regard to any interfaces known to exist behind casing.

When pressure data is acquired, either in association with wireline pressure-depth surveys conducted as part of the open hole logging program, pressure measurements taken upon completion or recompletion of a well, or in association with the annual pool pressure survey, one digital copy of this data should be submitted as an Excel file, or space delimited ASCII file(s) on USB, SFTP or other medium as approved by the *Regulator* in accordance with the requirements of the evaluation program conducted. The format for data submission should be columnar: real time (hh mm ss -24 hr clock) not elapsed time, pressure (kPa absolute) and temperature (°C).

The *Regulator* recognizes the flexibility needed by operators in conducting such surveys. To this end, the *Regulator* will accept the valid results of any survey conducted during this time, provided the wells concerned were included in the survey program, and were subsequently considered to be acceptable by the *Regulator* as part of the overall pool survey. When permanent downhole gauges are used, the *Regulator* will consider alternative programs for pressure data acquisition and reporting on a case-by-case basis. Acceptance of the survey program will be subject to the *Regulator* being satisfied that it provides for the accurate determination of the static pressure in the pool.

Section 203 – Gas Venting Records

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203 An operator must ensure that a record is kept of the following information in respect of each gas venting referred to in paragraph 82(c):
(a) a description of the emergency situation that justified the venting;
(b) a description of the venting, the date it occurred and its duration; and
(c) the volume of gas vented.

No guidance required at this time.

Section 204 – Compressor Records

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204 An operator must ensure that a record containing the following documents and information is kept in respect of the compressors referred to in subsection 84(1):
(a) information demonstrating, with supporting documents, that the continuous monitoring device referred to in subsection 84(2) has been calibrated in accordance with the

manufacturer's recommendations such that its measurements have a maximum margin of error of ±10%; and
(b) for each compressor, if its maximum flow rate limit under subsection 84(3) or (4) has been exceeded,
(i) its serial number, make and model,
(ii) the date on which the maximum flow rate limit was exceeded,
(iii) the flow rate indicated by the continuous monitoring device when the maximum flow rate limit was exceeded, and
(iv) a description of the corrective measures that were taken and the dates on which they was taken.

No guidance required at this time.

Section 205 – Fugitive Emission Records

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205 An operator must ensure that a record containing the following information is kept in respect of any fugitive emission from an installation that is detected:
(a) the date on which the emission was detected;
(b) the type of equipment from which the emission was released and its location within the installation or identifier;
(c) the means by which the emission was identified; and
(d) a description of the corrective measures that were taken and the dates on which they were taken.

Refer also to the requirements and associated guidance under section 179 of the *Framework Regulations* for reportable incidents, which includes reporting of pollution and leaks of hazardous substances based on the actual quantity released or the potential quantity that could have been released.

Section 206 – Record Retention Period

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206 An operator must ensure that a record referred to in any of sections 203 to 205 is retained for five years after the day on which the record is created.

No guidance required at this time.

DIVING PROJECTS OR CONSTRUCTION ACTIVITIES

Section 207 – Weekly Status Reports – Diving and Construction

207 (1) An operator must ensure that weekly reports are submitted to the Board on the status of any diving project or construction activities.

Content of reports

(2) The weekly status reports must contain the following documents and information:
(a) the project number assigned by the Board;
(b) information identifying, and indicating the current location and status of, all operations sites and support craft used in the diving project or construction activities;
(c) a description of the works and activities carried out during the preceding week;
(d) an indication of the total number of persons involved in the works and activities who, during the week, were at, or transferred to or from, the operations sites and, if applicable, the means by which they were transferred;
(e) a summary of emergency drills and exercises that were completed and reportable incidents that occurred during the week;
(f) an indication of the quantities of consumable substances that are critical to safety that are currently at each operations site; and
(g) a summary of the verification, inspection, monitoring, testing, maintenance and operating activities that are critical to safety that were carried out during the preceding week.

General

- Reports should cover the period from the date the program is commenced to the date the program is completed.
- All reports submitted to the *Regulator* should be accurate, complete and provided in a searchable electronic format (e.g., PDF).
- All reports should be submitted to the C-NLOPB at information@cnlopb.ca or to the CNSOPB at info@cnsopb.ns.ca.
- All reports should either be submitted to the *Regulator* or made available electronically for download.

Content

- Reports should also consider any conditions or commitments for observation or reporting in the *Development Plans* (if applicable), associated Environmental Assessments and Impact Assessments or other requirements as specified in the OA.
- With respect to paragraph 207(2)(b) of the *Framework Regulations*:
    - Support craft includes all vessels or aircraft (e.g., chase vessels, passenger craft).

    - Operations site includes all installations and vessels (e.g., diving vessels, construction vessels).
- With respect to subparagraph 207(2)(c) of the *Framework Regulations*, this should include the following:
    - The number of divers in saturation, as applicable.
    - A status represented by percentages of the completion of associated work activities each day and in total.
    - A summary of any inspections undertaken.
    - The dates of any workplace committee meetings held.

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216. *ISO 10440-1 Rotary-Type Positive-Displacement Compressors for Petroleum, Petrochemical, and Natural Gas Industries, November 2007 (identical to API Std 619)*
217. *ISO 13354 Petroleum and Natural Gas Industries – Drilling and production equipment – Shallow Gas Diverter Equipment, May 2014*
218. *ISO 13623 Petroleum and natural gas industries — Pipeline transportation systems, September 2017*
219. *ISO 13628 Petroleum and natural gas industries - Design and operation of subsea production systems (series, dates vary)*
220. *ISO 13702 Oil and gas industries - Control and mitigation of fires and explosions on offshore production installations - Requirements and guidelines, March 2024*
221. *ISO 13703 Petroleum and Natural gas industries – Design and Installation of piping systems on offshore production platforms, December 2000*
222. *ISO 14001 Environmental management systems – requirements, September 2015*
223. *ISO 14224 Petroleum, petrochemical and natural gas industries - Collection and exchange of reliability and maintenance data for equipment, September 2016*
224. *ISO 14692-3 Petroleum and natural gas industries - Glass-reinforced plastics (GRP) piping – Part 3: System Design, August 2017*
225. *ISO 15138 Petroleum and natural gas industries – Offshore Production Installations - Heating, ventilation and air-conditioning, June 2018*
226. *ISO 15544 Oil and gas industries - Offshore production installations - Requirements and guidelines for emergency response, June 2024*
227. *ISO 15547-1 Plate Heat Exchangers for General Refinery Services - Part 1 - Plate-and-Frame Heat Exchangers (identical to API Std 662-1), November 2005*
228. *ISO 17776 Petroleum and natural gas industries - Offshore production installations - Major accident hazard management during the design of new installations, December 2016*
229. *ISO/TS 17969 Petroleum, petrochemical and natural gas industries - Guidelines on competency management for well operations personnel, November 2017*
230. *ISO 19900 Petroleum and natural gas industries — General requirements for offshore structures, June 2019*
231. *ISO 19901-1 Petroleum and natural gas industries — Specific requirements for offshore structures — Part 1: Metocean design and operating considerations, October 2015*
232. *ISO 19901-2 Petroleum and natural gas industries — Specific requirements for offshore structures — Part 2: Seismic design procedures and criteria, July 2022*
233. *ISO 19901-3 Oil and gas industries including lower carbon energy – Specific requirements for offshore structures – Part 3: Topsides Structure, January 2024*
234. *ISO 19901-4 Petroleum and natural gas industries — Specific requirements for offshore structures — Part 4: Geotechnical and foundation design considerations, July 2016*
235. *ISO 19901-5 Petroleum and natural gas industries – Specific Requirements for Offshore Structures – Part 5: Weight management, November 2021*

236. *ISO 19901-6 Petroleum and natural gas industries - Specific requirements for offshore structures - Part 6: Marine operations, December 2009*
237. *ISO 19901-7 Petroleum and natural gas industries – Specific Requirements for Offshore Structures – Part 7: Station keeping systems for floating offshore structures and mobile offshore units, May 2013*
238. *ISO 19901-8 Oil and gas industries including lower carbon energy — Offshore structures — Part 8: Marine soil investigations, September 2023*
239. *ISO 19901-9 Petroleum and natural gas industries – Specific requirements for offshore structures – Part 9: Structural Integrity Management, July 2019*
240. *ISO 19901-10 Petroleum and natural gas industries — Specific requirements for offshore structures — Part 10: Marine geophysical investigations, March 2021*
241. *ISO 19902 Petroleum and natural gas industries — Fixed steel offshore structures, December 2020*
242. *ISO 19903 Petroleum and natural gas industries — Concrete offshore structures, August 2019*
243. *ISO 19904-1 Petroleum and natural gas industries — Floating offshore structures – Part 1: Ship-shaped, semi-submersible, spar and shallow-draught cylindrical structures, May 2019*
244. *ISO 19905-1 Oil and gas industries including lower carbon energy — Site-specific assessment of mobile offshore units — Part 1: Jack-ups: elevated at a site, November 2023*
245. *ISO/TR 19905-2 Petroleum and natural gas industries — Site specific assessment of mobile offshore units – Part 2: Jack-ups commentary and detailed sample calculation, December 2012*
246. *ISO 19905-3 Petroleum and natural gas industries — Site-specific assessment of mobile offshore units, March 2021*
247. *ISO 19906 Petroleum and natural gas industries — Arctic offshore structures, July 2019*
248. *ISO 21457 Petroleum, petrochemical and natural gas industries – Materials selection and corrosion control for oil and gas production systems, September 2010*
249. *ISO 21789 Gas turbine applications—Safety, July 2022*
250. *ISO 24817 Petroleum, petrochemical and natural gas industries - Composite repairs for pipework - Qualification and design, installation, testing and inspection, August 2017*
251. *ISO 28300 Petroleum, petrochemical, and natural gas industries – Venting of atmospheric and low-pressure storage tanks, June 2008*
252. *ISO 29001 Petroleum, petrochemical and natural gas industries – Sector-specific quality management systems - Requirements for product and supply organizations, May 2020*
253. *ISO 31000 Risk management – Guidelines, December 2018*
254. *ISO 31010 Risk management - Risk assessment techniques, June 2019*
255. *ISO 35101 petroleum and natural gas industries – Arctic operations – Working Environment, October 2017*
256. *ISO 35102 Petroleum and natural gas industries – Arctic operations – Escape, evacuation and rescue from offshore installations, April 2020*
257. *ISO 35106 Petroleum and natural gas industries: Arctic Operations: Metocean, Ice and Seabed Data, December 2017*
258. *ISO 45001 Occupational health and safety management systems – requirements, March 2018*
259. *ISO 80079-36 Explosive atmospheres – Part 36: Non-electrical equipment for explosive atmospheres – Basic methods and requirements, February 2016*
260. *LR Guidance Notes for Technology Qualification, 2022*
261. *LR Rules and Regulations for the Classification of Offshore Units, July 2024*
262. *McInnes Cooper, Offshore Oil and Gas Decommissioning Best Practices, 2016*
263. *NFPA 1 – Fire Code, September 2023*
264. *NFPA 10 Standard for Portable Fire Extinguishers, September 2021*
265. *NFPA 11 Standard for Low-, Medium-, and High-Expansion Foam, December 2023*
266. *NFPA 12 Standard on Carbon Dioxide Extinguishing Systems, April 2021*

267. *NFPA 13 Standard for the Installation of Sprinkler Systems, September 2024*
268. *NFPA 14 Standard for the Installation of Standpipe and Hose Systems, September 2023*
269. *NFPA 15 Standard for Water Spray Fixed Systems for Fire Protection, December 2020*
270. *NFPA 17 Standard for Dry Chemical Extinguishing Systems, May 2023*
271. *NFPA 17A Standard for Wet Chemical Extinguishing Systems, May 2023*
272. *NFPA 20 Standard for the Installation of Stationary Pumps for Fire Protection, September 2024*
273. *NFPA 24 Standard for the Installation of Private Fire Service Mains and Their Appurtenances, May 2024*
274. *NFPA 25 Standard for the Inspection, Testing and Maintenance of Water-Based Fire Protection Systems, September 2022*
275. *NFPA 30 Flammable and Combustible Liquids Code, May 2023 (this document is also incorporated by reference in the OHS Regulations)*
276. *NFPA 37 Standard for the Installation and Use of Stationary Combustion Engines and Gas Turbines, December 2023*
277. *NFPA 69 Standard on Explosion Prevention Systems, December 2023*
278. *NFPA 72 National Fire Alarm and Signaling Code, September 2024*
279. *NFPA 80 Standard for Fire Doors and Other Opening Protectives, September 2024*
280. *NFPA 101 Life Safety Code, September 2023*
281. *NFPA 105 Standard for Smoke Door Assemblies and Other Opening Protectives, September 2024*
282. *NFPA 110 Standard for Emergency and Standby Power Systems, May 2024*
283. *NFPA 400, Hazardous Materials Code, May 2024*
284. *NFPA 750 Standard on Water Mist Fire Protection Systems, April 2022*
285. *NFPA 1961 Standard on Fire Hose, August 2019*
286. *NFPA 1962 Standard for the Care, Use, Inspection, Service Testing, and Replacement of Fire Hose, Couplings, Nozzles, and Fire Hose Appliances, November 2017*
287. *NFPA 2001 Standard on Clean Agent Fire Extinguishing Systems, September 2021*
288. *NOPSEMA Guidance Note GN 1051 Supporting Safety Studies, June 2020*
289. *NOPSEMA Guidance Note GN 0271 Control measures and performance standards, June 2020*
290. *NORSOK D-001 Drilling Facilities, December 2012*
291. *NORSOK D-002 Well Intervention Equipment, January 2020*
292. *NORSOK D-007 Well testing, clean-up and flowback systems, March 2021*
293. *NORSOK D-010 Well integrity in drilling and well operations, December 2021*
294. *NORSOK M-001 Materials Selection, October 2014*
295. *NORSOK S-001 Technical Safety, May 2021*
296. *NORSOK Z-013 Risk and emergency preparedness assessment, January 2024*
297. *NORSOK Z-015 Temporary Equipment, December 2020*
298. *Norwegian Oil and Gas Association Recommended Guidelines for Well Integrity – No. 117, November 2017*
299. *Oil and Gas Conservation Regulations of Alberta*
300. *Offshore Energies UK Good Practice in Fire Management in Offshore Accommodation, October 2019*
301. *Offshore Energies UK Guidance on the Management of Ageing and Life Extension Aspects of Electrical, Control & Instrumentation Equipment, September 2020*
302. *Offshore Energies UK Guidance on the Management of Ageing and Life Extension for UKCS Oil and Gas Installations, September 2020*
303. *Offshore Energies UK Guidance on the Management of Aging and Life Extension of Subsea Pipelines and Risers, September 2020*
304. *OTC-27352-MS - Special Oversight Measures for Deepwater and Critical Wells in Harsh Environments, M. Conway, October 24, 2016*

305. *Renewable UK, Guidelines for the Selection and Operation of Jack-ups in the Marine Renewable Energy Industry, February 2013*
306. *SPE 20430 Mud Gas Separator Sizing and Evaluation, December 1991*
307. *Statement of Canadian Practice with respect to the Mitigation of Seismic Sound in the Marine Environment (www.dfo-mpo.gc.ca)*
308. *Transportation of Dangerous Goods Act*
309. *Transport Canada Publication TP 127E Ships Electrical Standards for Marine Systems*
310. *Transport Canada's TP 14475 Canadian Life-Saving Appliance Standard*
311. *UKOOA Guidelines for Safe Movement of Self-Elevating Offshore Installation (Jack-Ups), April 1995.*
312. *UKOOA Guidelines for the Management of Offshore Helideck Operations , February 2005*
313. *United Nations Convention on the Law of the Sea (UNCLOS)* (www.un.org)
314. *WMO Guide to Meteorological Instruments and Methods of Observation, 2023*
315. *WMO Manual on Codes, 2019*
316. *WMO Guide to the Implementation of Education and Training Standards in Meteorology and Hydrology, 2023*

6.0 Appendix A – Flow and Shut-In Periods for Formation Flow Tests

For exploration and delineation wells, a test should consist of those periods indicated by A, B and C as noted:

Table A1: Flow and Shut-In Periods

	Period	Status	Period Duration	Objectives
A	Initial Flow Initial Shut-In	Mandatory Mandatory	5 – 10 minutes 90 minutes	Relieve supercharging within invaded zone. Determine initial reservoir pressure.
B	Clean-Up Flow	Mandatory	As Required	Establish flow of in-situ fluids at surface.
C	Primary Flow Primary Shut-In	Mandatory Mandatory	4 – 24 hours 8 – 48 hours	Produce in-situ fluids at stabilized rates. Acquire representative fluid samples. Acquire build-up data to identify flow behaviour and determine reservoir characteristics.
D	Sampling Flow	Optional	As Required	Acquire subsurface fluid samples.
E	Secondary Flow Secondary Shut-In	Optional Optional	Up to 4 days As Required	Address additional operator objectives. Address additional operator objectives.

The above periods are also intended to prevent confusion between the secondary objectives of a formation flow test and the broader, longer term objectives of an extended formation flow test as referenced in the *Accord Acts*. The *Regulator* recognizes that minor deviation from suggested period durations indicated in in the above table may be warranted dependent on the specific reservoir response and stated test objectives.

7.0 Appendix B – GGE Program Data Submission Requirements

Table B1: 2D Seismic Survey - Data Submission Requirements

Data Required	Format	Remarks
Track plot location data with time stamp (final navigation data)	ASCII	• P1/90 or equivalent information • All location data should reference the NAD 83 datum and identify the appropriate UTM zone
Digital seismic traces - final migrated PSTM and PSDM (if generated)	SEG-Y	• When PSTM or PSDM outputs not available, last processing output is required • Copies of other versions of the processed seismic data, if generated, may also be requested
Digital seismic traces – processed angle stacks	SEG-Y	• Seismic traces for each of the angle stacks processed (e.g., near, near-mid, mid, far-mid, and far angle stacks)
Digital images of seismic sections - fully annotated (includes side legend with processing and acquisition parameters and horizontal annotation with CDP and SP numbering), final processed data (PSTM and PSDM)	TIFF and PDF	• Required for each line • Digital images should have appropriate vertical and horizontal scales to best represent the data at a workable level of detail
Velocity data	ASCII	• Including line number, SP, time, RMS pairs for both stacked and migrated velocities

Table B2: 3D Seismic Survey - Data Submission Requirements

Data Required	Format	Remarks
Track plot location data with time stamp (final navigation data)	ASCII	• P1/90 or equivalent information • All location data should reference the NAD 83 datum and identify the appropriate UTM zone
Polygonal position data (full fold outline)	ASCII	• Survey inflection points describing the corner points in in-line/cross-line, latitude/longitude and UTM Coordinates • Grid information must be submitted in a format such that it is useable within software systems used by the *Regulators*
Digital seismic traces - final migrated PSTM and PSDM (if generated)	SEG-Y	• When PSTM or PSDM outputs not available, last processing output is required • Copies of other versions of the processed seismic data, if generated, may also be requested
Digital seismic traces – processed angle stacks	SEG-Y	• Seismic traces for each of the angle stacks processed (e.g., near, near-mid, mid, far-mid, and far angle stacks)
Digital images of seismic sections - fully annotated (includes side legend with processing and acquisition parameters and horizontal annotation with CDP and SP numbering), final processed data (PSTM and PSDM; last processing output were not available)	TIFF and PDF	• Required for in-lines, cross-lines and horizontal (time and depth) slices • Digital images should have appropriate vertical and horizontal scales to best represent the data at a workable level of detail • The spacing for in-lines and cross-lines should be 500 m and horizontal slices at 500 milliseconds (ms) in time and 500 m in depth
Velocity data	ASCII/SEG-Y	• Including line number, SP, time, RMS pairs for both stacked and migrated velocities

Table B3: Geohazard Survey - Data Submission Requirements

Data Required	Format	Remarks
Track plot location data with time stamp (final navigation data) for 2DHR/3DHR and SBP	ASCII	• P1/90 or equivalent information • All location data should reference the NAD 83 datum and identify the appropriate UTM zone
Digital seismic traces of 2DHR or 3DHR final processed data Digital seismic traces of SBP final processed data (relative amplitude and AGC scaled)	SEG-Y	• Applies to 2DHR, reprocessed 3DHR (acceptable for deepwater only, >500 m) and SBP data • Copies of other versions of the processed seismic data, if generated, may also be requested
Digital images of seismic sections - fully annotated (includes side legend with processing and acquisition parameters and horizontal annotation with CDP and SP numbering), final processed data Digital images of SBP sections (relative amplitude and AGC scaled)	TIFF and PDF	• For 2DHR – all lines • For 3DHR reprocessed – in-lines and cross-lines at 500 m intervals • For SBP – all lines
Digital images or video of seabed imagery and boreholes (if obtained)	TIFF/AVI/MP4 or equivalent	
Processed bathymetric data	ASCII or equivalent	• x, y and z (depth) format
Processed side scan sonar line and mosaic data	XTF/JSF or equivalent	

Table B4: Controlled-Source Electromagnetic (CSEM) Survey - Data Submission Requirements*

Data Required	Format	Remarks
Track plot location data with time stamp (final navigation data)	ASCII	• P1/90 or equivalent information • All location data should reference the NAD 83 datum and identify the appropriate UTM zone
Final processed data, 2D and 3D model data if generated	SEG-Y or equivalent	
AVO/MVO/PVO data (all harmonics)	PDF/TIFF or equivalent	
Fully annotated images of final processed data	TIFF and PDF	• Resistivity cross-sections on all receiver lines and in-line/cross-line/depth slices through the 3D model at 500 m intervals

*Other electromagnetic surveys must submit equivalent data to CSEM requirements when applicable

Table B5: Gravity/Magnetics Survey - Data Submission Requirements

Data Required	Format	Remarks
Track plot location data with time stamp (final navigation data)	ASCII	• P1/90 or equivalent information • All location data should reference the NAD 83 datum and identify the appropriate UTM zone
Final processed data	ASCII/SEG-Y or equivalent	• Including final navigation and calculated field data • Gravity specific – Records of processed gravity data in ASCII format containing latitude/longitude, water depth, observed absolute value of gravity, Bouger anomaly and Free-air anomaly, for all data points • Magnetic specific – Digital records of processed magnetic data in ASCII format containing latitude/longitude, total field value corrected for diurnal variation and residual magnetic field for all readings
Digital images of interpretation maps	TIFF and PDF	• Include all maps from the interpretation report as separate geo-referenced TIFF images

Table B6: Geological Survey - Data Submission Requirements

Data Required	Format	Remarks
Track plot location data with time stamp (final navigation data)	ASCII	• P1/90 or equivalent information • All location data should reference the NAD 83 datum and identify the appropriate UTM zone
Processed data	ASCII/SEG-Y or equivalent	• Including final navigation and calculated field data (e.g., multi-beam, SBP, heat flow measurements, geochemistry, biostratigraphy • Processed field data for each system, such SBP seismic traces in SEG-Y format, bathymetric data in x, y and z (depth) format, heat flow measurements in ASCII format, etc.
Digital images or video of seabed imagery (if obtained)	TIFF/AVI/MP4 or equivalent	
Digital prints of core photographs and core logging	TIFF and PDF	
Digital images of interpretation maps	TIFF and PDF	• Include all maps from the interpretation report as separate geo-referenced TIFF images
Results of recovered samples and associated studies	Suitable Format	• Discuss with *Regulator* on requirement to submit any obtained samples
Any other information used or produced during the interpretation of the data	Suitable Format	• Discuss with *Regulator* on requirement to submit any obtained samples

Table B7: Geotechnical Program - Data Submission Requirements

Data Required	Format	Remarks
Track plot location data with time stamp (final navigation data)	ASCII	• P1/90 or equivalent information • All location data should reference the NAD 83 datum and identify the appropriate UTM zone
Digital images or video of seabed imagery and boreholes (if obtained)	TIFF/AVI/MP4 or equivalent	
Processed bathymetric data	ASCII or equivalent	• x, y and z (depth) format
Processed side scan sonar line and mosaic data	XTF/JSF or equivalent	
Any other information used or produced during the interpretation of the data	Suitable Format	• Discuss with *Regulator* on requirement to submit any obtained samples

Table B8: Environmental Program - Data Submission Requirements

Data Required	Format	Remarks
Track plot location data with time stamp (final navigation data)	ASCII	• P1/90 or equivalent information • All location data should reference the NAD 83 datum and identify the appropriate UTM zone
Photographs/Videos	As applicable	
Samples	As applicable	
Any data or information which was collected during the program	As applicable	• Discuss with *Regulator*, scope of reporting will be determined on a case-by-case basis