Data Acquisition and Reporting Guidelines

February 2020

C-NLOPB

ISBN 978-1-927098-03-5

Table of Contents

Page No.

1.0 Introduction

The Canada-Newfoundland and Labrador Offshore Petroleum Board ("C-NLOPB") herein referred to as the Board is the authority responsible for the administration of the regulations pertaining to the exploration for and production of hydrocarbons in the Newfoundland and Labrador offshore area.

The authority to issue guidelines and interpretation notes with respect to regulations is specified under subsection 151.1(1) of the Canada-Newfoundland Atlantic Accord Implementation Act.

Attention: *These guidelines were developed in respect of the "Newfoundland Offshore Petroleum Drilling and Production Regulations" hereafter referred to as the regulations and apply to operators working within the Newfoundland & Labrador Offshore Area. These guidelines were developed jointly by the Canada-Newfoundland Offshore Petroleum Board (C-NLOPB) and the Canada Nova Scotia Offshore Petroleum Board (CNSOPB) which follow mirror regulations. The guidance provided in the C-NLOPB version and that issued by the CNSOPB is largely identical, however in a few areas differences do exist reflecting administrative approach and the unique challenges of evaluation in each jurisdictional area.*

These guidelines have been prepared to assist operators in complying with regulatory requirements pertaining to well, pool and field evaluations, and to inform them as to the form and manner in which related information and data should be submitted to the Board. Copies of this document may be obtained online from the Board's web site, www.cnlopb.ca.

- **Administrative Authority**

Under the provisions of the Canada-Newfoundland Atlantic Accord Implementation Act, the Board has delegated authority in matters related to the administration of this guideline and the regulations under which they were developed to the Board's Chief Conservation Officer. All references to the "Board" made within this guideline document in respect of well classification, approvals, programs, notifications, queries or clarifications, equivalency, or the submission of data or samples, or disposal of same should be directed to the Board's Chief Conservation Officer unless otherwise stated or directed.

- **Data Submission Requirements**

The international system of units (SI) should be used in the submission of information or data to the Board. Standard conditions as referenced in this document mean atmospheric pressure of 101.325 kPa (absolute), and ambient temperature of 15 °C.

Note: *Data in formats other than those prescribed in these guidelines may be acceptable. Persons wishing to submit data in another format should ensure this format is acceptable to the Board's Chief Conservation Officer.*

2.0 Evaluation Programs Under the Drilling and Production Regulations

Introduction:

The requirements for a "Well Data Acquisition Program" and "Field Data Acquisition Program" are outlined under Sections 11(b) and 6(i) of the regulations. This document provides guidance in respect of the following evaluation areas for both well and field data acquisition programs:

- mud logging;
- drill cuttings;
- conventional and sidewall cores;
- logs and surveys;
- testing and sampling of formations;
- fluid sampling and analysis;
- pool pressure surveys.

Well Data Acquisition Program:

An operator of an exploration or delineation well is required to submit a well data acquisition program as part of the application required in support of a "Well Approval" to drill a well under Section 11 of the regulations.

The application should be filed 21 days prior to the anticipated spud date. The submission should contain the details of the evaluation program proposed, to the extent that such detail is possible prior to commencement of drilling. Issuance of a well approval will be dependent, in part, upon whether the program proposed provides for the comprehensive evaluation of the well as required by regulations. During the approval process, the operator may be requested to meet with the Board's staff to discuss the application and respond to any questions or concerns brought forward.

An operator of a development well may expedite the well approval process for such wells by including its well data acquisition program as part of the field data acquisition program required in support of an "Operations Authorization". Where elements of a well data acquisition program for development wells can be standardized, (i.e. cuttings collection, logging, etc.) the operator need only reference that component as detailed in the field data acquisition program. Where an operator wishes to deviate from its "standard" program, the operator need only include the specific additions to the program in support of the application for well approval filed with the Board.

Field Data Acquisition Program:

The operator of a field undergoing development must submit a field data acquisition program as required by Section 6 of the regulations in support of its application for "Operations Authorization". This program should outline the operator's evaluation strategy for a well, pool or field in support of

Sections 6 and 11 of the regulations and be satisfactory to the Board in respect of evaluation expectations outlined in this document. The operator should design its program to provide sufficient flexibility to respond to changing evaluation needs as the field matures.

The term of a field data acquisition program will be linked with the term of the operations authorization. Upon expiry, the operator must file an update to its program in association with renewal of the authorization. The update may represent a request for continuance of the program, or may reflect amendments in response to changing evaluation needs as the field matures.

Wells drilled during the term of an operations authorization may reference in the well approval, a “standard” approach to well evaluation where it has been included in the field data acquisition program. Alternatively, an operator may define its well data acquisition program as part of the application for a well approval to drill a well.

Notification of a Conservation Officer:

An operator must notify a conservation officer in accordance with Section 50 of the regulations, where part of the well data acquisition program, or the field data acquisition program cannot be implemented. Two types of notification are recognized:

Type 1 - deviation from a well or field data acquisition program prior to spudding a well; or,

Type 2 - deviation from a well or field data acquisition program during the course of drilling a well in response to operational issues, or in response to changing reservoir conditions.

Where an operator seeks to make a Type 1 deviation, the request must be documented and supported in writing and submitted to the attention of the Chief Conservation Officer as an “Amendment to a Well Data Acquisition Program”, or as an “Amendment to a Field Data Acquisition Program”. Further direction in respect of this matter may be obtained by contacting the Chief Conservation Officer prior to filing an amendment.

Where an operator seeks to make a change under Type 2 deviation it will be treated as an operational change and expedited accordingly. For this purpose, the operator should file, as soon as circumstances permit, the form **“Operational Waiver/Notification from an Approved Well Data Acquisition Program”** found under **Appendix “A”** of this guideline and to direct it to the designated conservation officer responsible.

2.1 Evaluation Program Scope

The guidance provided in this document is intended to assist the operator in the following areas:

- program design;
- operational guidance;
- deposition and analyses of samples; and,
- reporting requirements.

(1) Program Design

In respect of a well data acquisition program, the Board will seek to ensure that the program proposed provides for a comprehensive evaluation of the well, consistent with the class of well being drilled. With respect to the use of drilling mud systems, please refer to the “Offshore Waste Treatment Guidelines, December 15, 2010”.

To this end, the Board discourages the use of:

- turbo drilling in exploration wells, due to the destruction of cuttings, unless the operator provides justifiable reasons for its use; and,

- mud systems other than water based mud in exploration wells, unless adequate justification is provided in the application for “Well Approval”.

The Board recognizes the additional challenges that drilling “wildcat” wells, drilling in “rank” exploration areas (i.e. new basins) or drilling in deep water environments present. The Board will weigh the well evaluation expectations reflected in these guidelines against reasonable arguments for relaxation supported by operators in their program design.

The Board will review both well and field data acquisition programs employing the criteria defined below. Where the operator is aware of exceptional or special circumstances which would require it to deviate from regulatory expectations defined in these guidelines, the operator should state its case in writing preferably prior to making application for “well approval” sought under these regulations. Such “exceptional or special” circumstances should be introduced and discussed in a pre-approval meeting with the Board’s staff. Where the Board accepts the reasons for deviation, the Board will reference the exemption in granting its approval.

In general terms, the criteria for assessing the acceptability of a well data acquisition program is linked to the well's classification at the time the application for “well approval” is filed.

i) programs for exploratory wells should:

  - provide a basic evaluation of all intervals; and,
  - focus evaluation on intervals where hydrocarbons are encountered to ensure that a suitable basis for assessing any potential discovery is established.

ii) programs for delineation wells should:

  - attempt to resolve uncertainties regarding significant hydrocarbon bearing and other relevant intervals in order to enable an assessment of the development potential of the field to be made.

iii) programs for development wells should:

- attempt to resolve any remaining uncertainties regarding targeted production intervals, and establish baseline measurements for subsequent production monitoring programs; and,
- provide a level of evaluation outside of targeted production intervals that is commensurate with the development potential of intervals encountered.

Acceptability of a field data acquisition program will be based upon whether the program provides for data gathering in support of well and pool monitoring, and responds to changing conditions respecting wells and/or the performance of wells and/or pools during the operational life of the field.

Use of New or Equivalent Technology: Subject to the Act and its regulations, the Board encourages the application of new or equivalent technology where it has been shown to be equivalent in practice to current technology in use in other jurisdictions for similar purposes, or where it can or will be demonstrated to be equivalent against existing practice in use in the Board's jurisdictions.

(2) Operational Guidance

Guidance is provided throughout this document where clarification of regulatory requirements is required, or where a consistency of approach is necessary to assist operators in complying with the regulations.

(3) Deposition of Samples and Analysis Requirements

Sections 53, 54 and 55 of the regulations cover the deposition requirements respecting samples collected as part of a well or field data acquisition program. Section 77 of the regulation addresses the submission requirements respecting data and analysis to the Board. Guidance is provided where applicable.

Submission of samples to the Board is typically required 60 days after the rig release date, or where analysis of a sample(s) is undertaken, the remaining sample(s) is to be submitted to the Board within 60 days following completion of the analysis.

Submission of data and analysis to the Board is typically required 60 days after the day on which the measurement, sample, test, or well operation is completed.

Note: *An extension to the 60 day requirement stipulated above for submission of samples, data or analyses to the Board may be accepted where a written request is filed with the Board, and the delay respecting the submission is justified by the operator and accepted by the Board.*

The operator should contact the relevant Board staff (Appendix B1) for clarification related to the submission of samples detailed in these guidelines, or where alternative procedures are to be employed by the operator/contractor in the preparation of samples for submission to the Board. This includes containers used in housing and shipping samples, labeling, cleaning, etc.

Disposal of Samples or Data: Under Section 55 of the regulations, where an operator wishes to dispose of samples or data in their possession the operator must first notify the Board in writing outlining:

- the nature and volume of samples to be disposed of;
- the nature of data to be disposed of siting relevant information such as the title of document(s) and a brief summary of the contents.

Where the Board requests that the operator submit samples or data to the Board, the cost of delivery will be borne by the operator.

(4) Reporting Requirements

Operators are referred to the corresponding sections of this document for reporting guidance respecting evaluations conducted as part of either a well data acquisition program or field data acquisition program.

Operational Records and Reports:

An operator is required to submit one searchable PDF copy of any "operational" records and reports requested by the Board through these guidelines.

Well History Report:

An operator is required to submit the following within 90 days of the rig release date for exploration and delineation wells, and within 45 days of the well termination date for development wells. This includes any logs, surveys, analyses and reports relevant to evaluation programs conducted in support of a well data acquisition program.

- One searchable PDF file submitted on USB, SFTP or other medium approved by the C-NLOPB, of the well history report or any secondary report(s) relevant to evaluation programs conducted in support of a well data acquisition program.

- One copy of digital data related to cores, logs, surveys and analyses conducted, submitted in the format prescribed herein and on USB, SFTP or other medium approved by the C-NLOPB in support of a well data acquisition program.

Field Data Acquisition Programs:

An operator is required to submit the following of any log, survey, analyses or report resulting from evaluations conducted as part of a field data acquisition program. Submissions to the Board should be made within 90 days of acquiring the log or survey, or completion of the analyses or report

- One searchable PDF file submitted on USB, SFTP or other medium approved by the C-NLOPB, of any log or survey, analyses conducted or any report related to evaluation made under the field data acquisition program.

- One copy of digital data related to logs, surveys and analyses conducted, submitted in the format prescribed herein and on USB, SFTP or other medium approved by the C-NLOPB in support of a field data acquisition program.

3.0 Mud Logging of Wells

Section 28 of the regulations requires that the operator ensure that the drilling fluid system and associated monitoring equipment on a drilling unit is fully operational and maintained to allow for proper well evaluation.

3.1 Program Design

Equipment employed in the monitoring of drilling fluid returns is considered to be part of the "Drilling Fluid System" described in Section 28 of the regulations. The equipment installed should be capable of:

- continuous monitoring of drilling mud returns and provide for automatic detection and alarm in the event of any increase in gas levels; and,

- measuring and recording total hydrocarbon gas content, and recording the relative amounts of any methane, ethane, propane, and butane gas present in mud returns.

The operator must ensure for the purpose of proper well evaluation, that drilling is continuously monitored after the conductor casing has been installed in the well. In some instances, for example where multiple development wells are drilled from a common surface location, the Board may relax, upon request by the operator, the requirement to acquire mud log data in the up hole portion of these wells.

To this end, an operator should ensure that:

i) a record of the chemical and physical properties of the drilling mud are recorded for each hole section, and the record maintained on site;

ii) a "mud log" is kept on site recording the measurements noted in Appendix C1.

The operator is referred to **"Annex L – Water-Based Drilling Mud Report Form" of API RP 13-B-1 Recommended Practice for Field Testing Water-Based Drilling Fluid, 3ed. 2005;** and **"Annex O – Oil-Based Drilling Mud Report Form" of API RP 13B-2 Recommended Practice for Field Testing Oil-Based Drilling Fluid, 5ed. 2014** for guidance respecting the reporting format for i) above.

3.2 Operational Guidance

Equipment employed in the monitoring of gas content of drilling fluid should be maintained and calibrated in accordance with manufacturers recommended practice. Where maintenance and calibration records are not provided with the well history report, such records must be retained by the operator for 6 months following the termination of drilling and made available to the Board upon request.

3.3 Reporting Requirements

(a) "Operational" Records and Reports

The operator is required to report mud gas readings as part of the daily lithology report required by Section 84 of the regulations. These readings should be submitted to the Board in accordance with the daily reporting procedures for drill cuttings described in Section 4.3(a) of this document.

(b) Well History Report

The "Drilling Mud Report Form" and the "Mud Log" prepared for the well should be submitted in accordance with the reporting requirements detailed under Section 2.1(4) of these guidelines.

One digital copy of data represented on the "Mud Log" should be submitted on USB, SFTP or other medium approved by the C-NLOPB in LAS2 or LAS 3 format, or in any format acceptable to the Chief Conservation Officer.

4.0 Drill Cuttings

The following guidance is provided with respect to the sampling, submission and description of "drill cuttings" in support of a well data acquisition program.

4.1 Program Design

An operator is referred to the following regulatory expectations respecting the sampling of drill cuttings from a well.

- **Exploration/Delineation Wells**

Sampling of cuttings should commence at the base of surface casing with samples to be collected at 5 metre interval to the total depth of the well. Relaxation of these requirements by the Board may be given where requested and supported by the operator. Complete sets of the following three types of samples are required:

i) Two sets of washed and dried cuttings collected at 5 metre intervals for lithology identification:

- 1 set packed in 25 ml transparent plastic vials shipped to the Board - Appendix B1;

and,

- 1 set packed in 15 ml transparent plastic vials for the Board c/o the **Geological Survey of Canada (GSC)**, Calgary, AB - Appendix B1.

ii) One set of unwashed cuttings collected at 5 metre intervals for micropaleontological, palynological and nanno-fossil analyses, or other analyses as required. Each sample should consist of at least 500 grams of 'dried' cuttings placed in a plastic-lined cloth bag to be shipped to the Board - Appendix B1.

Where the well has been drilled with oil-based or synthetic mud, operators may be required to "pre-wash" all unwashed drill cuttings prior to submission.

Note: *The Board does not currently require the "pre-washing" of unwashed cuttings prior to submission. However, to minimize any potential health risk respecting cuttings from hole sections drilled with OBM/SBM, operators should ensure that samples are completely dried prior to submission.*

iii) One set of unwashed cuttings at 10 metre intervals for geochemical analyses. Each sample should consist of at least 500 grams of cuttings placed in a plastic container suitable for long-term storage similar to Petrocraft's 1 litre plastic wide-mouth container. The container should be filled to two-thirds full with cuttings, then filled with cold water (fresh or seawater) leaving a 1 cm air space. Four (4) drops of bactericide should be added to prevent the formation of gas from bacteria that are routinely found in cuttings samples. Rims should be cleaned to ensure a proper seal. Samples should be shipped to the Board, c/o the **Geological Survey of Canada (GSC)**, Calgary, AB (Appendix B1).

Where OBM or SBM is used in the drilling of the well, a 1 litre sample of "hole mud" should be captured and provided to the GSC along with drill cuttings captured for geochemical analysis. This mud sample should be acquired immediately after reaching TD and prior to logging for each hole section over which drill cuttings for geochemical analysis were acquired. Mud samples should be submitted to the GSC in durable plastic containers, e.g. Petrocraft's 1 litre jar.

- **Development Wells**

Consideration will be given to relaxing sampling requirements for drill cuttings in any development well where such sampling can be shown to be redundant to samples already taken in adjacent wellbores. In such instances, the operator of a field is encouraged to discuss its proposal for relaxation of drill cuttings with Board staff prior to submission of its field data acquisition program.

4.2 Deposition Requirements

In preparing samples for deposition from the drilling site, the operator must ensure that:

i) vials and jars used for samples are adequate to prevent deterioration or loss of the sample;
ii) all samples are clearly and indelibly labelled with the well name, location (i.e. field) and sample depth; and,
iii) all samples are carefully packed in labeled boxes or containers appropriate for shipment.

Samples must be delivered to the Board within 60 days following the rig release date of each well.

4.3 Reporting Requirements

(a) "Operational" Records and Reports

Section 84 of the regulations requires an operator to submit to the Board daily reports on the lithology of the formation drilled, and the nature of formation fluids encountered. Board Staff should have access to the daily reports via well monitoring web portals, or through email from the operator if web portals are unavailable.

(b) Well History Report

This report should include:

i) lithological and hydrocarbon show descriptions for all cutting samples;
ii) a summary table/chart of the lithostratigraphic units encountered and their geologic ages; and,
iii) 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 for well history reports, the Board requires that one digital copy of data be provided on USB, SFTP or other medium approved by the C-NLOPB in ASCII format, or any other format acceptable to the Chief Conservation Officer.

5.0 Conventional and Sidewall Cores

5.1 Program Design

An operator is referred to the following regulatory expectations respecting the taking of cores when preparing its data acquisition program for a well or field.

(a) Conventional Cores

An operator should include the criteria (e.g. drilling breaks, shows, etc.) to be followed for the cutting of core in its program in support of its application for well approval filed under Section 11 of the regulations.

- **Exploration Wells**

An operator should plan to cut core in an exploration well where hydrocarbons are encountered within the reservoir designated by the operator as the “primary” target for the well where coring criteria provided by the operator is met.

Where hydrocarbons are encountered within “secondary” targets, or within other potential reservoir quality horizons, coring is encouraged but left to the discretion of the operator.

The Board recognizes that “wildcat” wells, or wells drilled in “rank” exploration areas may pose additional challenges to acquiring conventional core. In wells where such challenges are identified, consideration will be given to waiving conventional coring expectations in favour of a sidewall coring program where the operator makes application providing adequate justification in support of its request for dispensation.

- **Delineation Wells**

An operator should plan to obtain core representative of the targeted reservoir interval(s). Coring should attempt to capture reservoir heterogeneity, and where applicable, attempt to cut fluid contacts anticipated.

Additionally, an operator is encouraged to cut core from other hydrocarbon-bearing formations encountered outside of the targeted reservoir interval(s) where coring criteria is satisfied.

- **Development Wells**

An operator should define its coring program strategy as part of its field data acquisition program required in support of the “Operations Authorization” issued for the field. The intent to core a well(s) should be executed through the well data acquisition program filed in support of a well approval to drill a well.

The coring program component of a field data acquisition program should capture the overall strategy with respect to coring needs for a pool or field. It should plan to sample productive reservoir within recognized pools in a manner designed to characterize productive reservoir, and resolve any uncertainty that may exist. A coring program should ensure that:

i) Core is acquired from select development wells to ensure spatial representation of all targeted horizons for the purpose of minimizing uncertainty with respect to geologic correlation, reservoir characterization and the depletion scheme proposed. This should include:

    - coring of gas, oil or water bearing intervals from select wells; and,
    - coring of reservoir intervals where an opportunity exists to assess the performance of the depletion scheme being employed.

ii) Special core analysis is directed at resolving the uncertainties identified in the development plan, and at assessing the potential of enhanced recovery schemes.

The coring of hydrocarbon-bearing reservoirs encountered outside of targeted horizons is encouraged, where the potential for development exists, and should be reflected in the coring program if applicable.

The operator should provide the following information in support of the coring program for a field:

i) A summary of coring to date, including the details of core cut and recovered on a well basis. This should include the interval cored and the formation or pool it represents and, the analyses conducted on each core;

ii) A summary of analyses for cores taken from those reservoirs targeted for development indicating those areas of uncertainty that need to be addressed in the proposed coring program;

iii) A list of the development wells for which the operator proposes to cut core noting the interval, pool or formation proposed for coring, the extent of coring proposed, and details as to the extent of analysis proposed for each core cut. A map(s) should accompany this list showing the location of all wells proposed to be drilled during the term of the field data acquisition program"; or,

iv) As an alternative to iii), a coring strategy with respect to the proposed development wells whereby the operator achieves spatial representation of core over targeted horizons for the purpose of mitigating any potential uncertainties.

(b) Sidewall Cores

The value of a sidewall coring program is recognized in allowing operators to acquire core specific to the depth of interest in a well by employing open-hole logs for exact depth-control purposes. Its value has been recognized for targeting potential source rock and for biostratigraphy purposes in exploration and delineation wells. The introduction of rotary sidewall coring technology has permitted the coring of reservoir quality rock as a supplement to conventional coring efforts, or as the only effective means to acquire core in the presence of thin reservoir sands or where the geology is uncertain.

- **Exploration Wells**

An operator of an exploration well should plan to obtain sidewall cores from all hydrocarbon-bearing reservoirs where conventional core was not obtained. The number of sidewall cores acquired should be sufficient to adequately characterize each petrophysically or geologically distinct zone.

Note: *An operator of a "wildcat" well, or well being drilled in a "rank" exploration area should plan to acquire sidewall core over potential source rock intervals, and all hydrocarbon bearing reservoir intervals where conventional core was not obtained.*

- **Delineation Wells**

The operator of a delineation well(s) should, for contingency purposes, plan to obtain sidewall cores over reservoirs targeted for appraisal where conventional core was either not obtained, or does not adequately characterize the reservoir represented by logs. In such cases, sidewall cores should be acquired (a) to reflect the reservoir heterogeneity as evident on logs, and (b) over reservoir intervals above and below fluid contacts encountered.

- **Development Wells**

The operator of a field under development should address the role of sidewall coring in respect of the coring program detailed in the field data acquisition program for the field. The program should address the contingency role, or value of a sidewall-coring program in a well where conventional coring was planned but not acquired.

Note: *The Board may request for any class of well, either as a condition of "well approval" or in response to viewing logs, that sidewall cores be taken from designated wellbore interval(s). To this end, the Board may request open-hole logs be electronically transmitted (i.e. via email or downloaded from a secure server, etc.) in accordance with 'Special Circumstances' noted in Appendix C2.*

5.2 Operational Guidance

- The operator is referred to **API RP 40 "Recommended Practice for Core Analysis", 2nd ed., February 1998** respecting the sampling of conventional or sidewall core from a well.

- **Conventional Core**

The operator should ensure that good coring practice is followed when acquiring conventional core. Notably, core should be labeled and marked immediately upon the recovery from a well for the purpose of preserving core orientation.

- **Sidewall Core**

The choice of technology employed (i.e. rotary or percussion coring) in obtaining sidewall cores should be appropriate to the analysis objectives outlined in the program.

5.3 Deposition and Analysis of Core Samples

The operator is referred to **API RP 40 "Recommended Practice for Core Analysis", 2nd ed., February 1998 (API RP 40)** respecting the deposition and analysis of conventional or sidewall core from a well.

(a) Deposition of Core from a Well

- **Conventional Core**

Core shipped from the drilling site must be placed in containers that prevent loss or deterioration of the sample. Containers must be clearly labelled with the well number and location, core number, depth interval and container number expressed as #__ of __.

Sampling of Core: Whole core shipped from the well site and received at a core handling facility should be sampled as required in accordance Sections 53 of the regulations to facilitate analysis as described under Section 5.3(b) below.

Any full diameter core selected for "special core analysis" should be preserved prior to shipment from the rig in accordance with Section 2.5 of **API RP 40**.

Submission of Core Slab to the Board: Following the removal of plug or full diameter core samples necessary for analysis, the remaining core, or a longitudinal slab core not less than one half the cross-sectional area of the core should be submitted to the Board in accordance with the following guidance.

Where the well has been drilled with oil-based or synthetic-based mud, operators may be required to wash all conventional core to remove the invading mud filtrate.

Note: *The Board does not currently require "washing" of conventional core prior to submission. In a case where mud or gels used in coring, or lubricants used in the cutting of core plugs, or saw marks resulting from the slabbing of the core obstructs the viewing of the core, the operator must ensure that the core face is cleaned prior to submission.*

Conventional core shipped to the Board should be placed in sturdy cardboard boxes of approximately 80 cm in length and deep enough to ensure that the weight of stacked boxes rests on the box frame and not on the enclosed cores. Where boxes have two or more internal sections, the core should be oriented with its top at the lower left corner and its base at the upper right corner as per the following sketch.

^	base
^	^
^	^
^	^
^	^
^	^
^	^
top	^

label

The top and base of the core should be clearly marked on the outside of the box. Sample numbers and intervals corresponding to whole diameter segments and plugs that have been removed for analysis should be marked on the inside of the box to assist in correlation of lithologies with reservoir properties. The box and its lid should be labelled in accordance with the above sketch on the end corresponding with the top of the core. Labels must clearly indicate the well name and location (i.e.

field), core number, box # expressed as "Box __ of __ ", the depth of the cored interval, and amount of recovery in metres.

Submission of Conventional Core Plugs to the Board: Each conventional core plug, or part thereof remaining after routine or special core analysis should be placed in a “plastic” jar or vial to mitigate issue of breakage associated with the use of glass containers during shipment. Each jar or vial should be clearly labelled with the well name and plug number noting the depth in relation to the conventional core from which the plug was cut. Samples should be securely packed for shipment, in appropriate cardboard or wooden boxes. Each box of samples should be labelled with the well name and location and box number expressed as "Box __ of ___ ".

- **Sidewall Cores**

Each sidewall core shipped from a rig should be clearly labelled and placed in a “plastic” jar or vial to mitigate the issue of breakage associated with the use of glass containers during shipment. Each jar or vial must be clearly labelled with the well name, noting the depth at which the sample was obtained.

Any sidewall cores cut or selected for “special core analysis” purposes should be preserved prior to shipment from a rig in accordance with Section 2.5 of **API RP 40**.

Submission of Sidewall Cores to the Board: Samples remaining after routine or special core analysis, or petrographic, biostratigraphic or other analyses should be securely packed for shipment, in appropriate cardboard or wooden boxes. Each sample, or remaining sample, after analysis should be placed in a “plastic” jar or vial to mitigate the issue of breakage associated with the use of glass containers during delivery. Each jar or vial must be clearly labelled with the well name, noting the depth at which the sample was obtained. Each box of samples should be labelled with the well name and location and box number expressed as "Box __ of ___ ".

Operators are requested to prepare a list to accompany any sidewall cores shipped to the Board identifying the sidewall cores or remaining sidewall cores included in the shipment and those sidewall cores destroyed as a result of analyses. The list should include the depth and run numbers associated with all sidewall cores taken from the well, and include the type of analyses performed, e.g. routine or special core analysis, petrographic, biostratigraphic, geochemical analysis, etc.

(b) Analysis of Core

The operator is referred to **API RP 40** respecting the analysis of conventional core, conventional core plugs, or sidewall core taken from a well.

Routine Core Analysis: Every conventional core should be analyzed to determine basic reservoir characteristics of all potential reservoir intervals in the core. Plug sampling of conventional core should take into account the lithological distribution, porosity and permeability variations and distribution of hydrocarbons. This should include measurements of at least the following characteristics:

i) porosity
ii) permeability, in the vertical direction, in the direction of maximum horizontal permeability and in the direction normal to the direction of maximum horizontal permeability, and
iii) fluid saturation

Rotary sidewall cores taken from reservoir intervals are subject to above measurements.

In addition to the analysis of plug samples taken, an operator should ensure that adequate samples of full diameter core are taken and analyzed where there are significant large scale heterogeneities in the whole core that are different from matrix properties obtained from analysis of plug samples.

Note: *Where additional core measurements and analysis are undertaken, the Board requires this information to be submitted by the operator. This would include the visual description of core for lithology and hydrocarbon shows, and readings of a core's natural gamma activity.*

Special Core Analysis: For a field being considered for development, or currently under development, special core analysis (SCAL) considerations should include:

- pore volume compressibility;
- overburden porosity and permeability;
- petrographic studies;
- electrical properties;
- capillary pressure; and,

for oil-bearing reservoirs:

- wettability;
- gas-oil relative permeability;
- water-oil relative permeability;
- waterflood tests; and,

for gas-bearing reservoirs:

- gas-water relative permeability;
- residual gas after water encroachment.

For fields under development, an operator should address remaining uncertainty through the coring program for the field submitted in support of the field data acquisition program.

5.4 Reporting Requirements

(a) "Operational" Records and Reports

The operator is required to describe cores as to the lithology encountered and hydrocarbon content and to provide this information in accordance with the daily reporting procedures for drill cuttings described in Section 4.3 of this document. When a sidewall coring program is conducted, the Board requires that the operator submit a log reporting sampling depths and the results achieved. This log should be submitted in accordance with the reporting requirements for logs detailed in Section 6.3 of this document.

(b) Well History Report

The well history report should include:

- lithological and hydrocarbon show descriptions with depth for conventional and sidewall core;
- sidewall core summary including tables for each coring run listing attempted shots and results (e.g. recovery, misfire); and,

those separate reports as conducted including:

- core analysis reports (routine and special) for both conventional and sidewall core indicating core numbers, interval cut and core recovery;
- core photographs where taken by an operator under natural and ultraviolet light of whole and/or slabbed core; and,
- petrographic, biostratigraphic and geochemical reports - and when such reports are not produced, a statement to this effect should be included.

In addition to the electronic copy requirements defined in Section 2.1(4) of this document, operators should submit on USB, SFTP or other medium approved by the C-NLOPB one digital copy of data for the following data types:

- “Routine Core Analysis” as a space delimited ASCII file, or as a DCIS (Digital Core Analysis Interchange Standard) file in accordance with Section 8 of **API RP 40**.
- “Core Photographs” in JPEG or TIFF formats.

6.0 Logs and Surveys

An essential component of well, pool and field evaluation includes those open and cased hole logs and surveys run in support of a well data acquisition program for the purpose of drilling a well, and for fields under development, those cased hole logs run during the operational life of a well in support of a field data acquisition program.

6.1 Program Design

6.1.1 Well Data Acquisition Program

Logs required in support of a well data acquisition program should include:

i) those open hole logs necessary to enable a comprehensive evaluation of the well; and,

ii) those cased hole logs necessary in support of well evaluation in exploration or delineation wells, or effective reservoir management in development wells.

(a) Open Hole Logging Program

The logging program proposed for an exploration, delineation or development well should ensure that sufficient logs necessary to enable a comprehensive evaluation of the well are acquired over all uncased intervals in the well below surface casing. For this purpose, the operator should take sufficient logs to:

i) permit an accurate calculation of the porosity, fluid saturation and fluid contact for all potential reservoirs;

ii) measure the size of the hole and the natural radioactivity of any formation;

iii) assist in determining the lithology of any formation; and,

iv) permit the calculation of accurate values of the vertical angle and direction of the hole and of the structural dip of the formations.

In respect of the above:

- a sufficient number of types of porosity-measuring logs should be acquired so that any effect of shaliness, hydrocarbons, complex lithology and the walls of the hole can be compensated for in determining the porosity of any formation;
- at least two types of porosity-measuring logs should be acquired if significant reservoir development is indicated in the portion of the hole in which the logs are to be taken;
- a sufficient number of types of resistivity-measuring logs should be acquired if significant reservoir development is indicated so that the distortion caused by filtrate invasion, thin beds, the drilling fluids and the walls of the hole can be compensated for in calculating formation resistivity.

The “types” of logs referenced above are considered to be “primary” logs and typically consist of density, neutron and sonic type logs for determining in-situ porosity, and induction and laterlog type logs for calculating formation resistivity. Resistivity tools should be capable of at least three depths of investigation in order to adequately characterize and compensate for mud filtrate invasion.

Equivalency: These guidelines do not limit the “types” of logs employed by an operator for these determinations, and encourage alternatives where equivalency in the determination of porosity and resistivity can be supported, or demonstrated to exist. The introduction of new technology should be demonstrated against established tools.

Conveyance: The Board does not restrict the means of conveyance employed by operators in logging wells. For this purpose, “logging while drilling” tools are deemed to be equivalent in measurement to “wireline” tools run on wireline in vertical wells, or conveyed on pipe in highly deviated or horizontal wells, providing data quality and depth control practices are not compromised. The operator would be expected to re-log a hole-section where data quality is compromised regardless of the type of logs or means of conveyance necessary.

(b) Cased Hole Logging Program

The cased hole logging program submitted in support of the well data acquisition program should consist of logs run to evaluate the quality of casing and/or liner cementation where justified in support of well evaluation and/or reservoir management; and logs run to acquire geophysical measurements or those logs run to evaluate flow contribution during formation flow tests.

- **Casing/Liner Cementation Evaluation**

The following information must be reported to the Board either on the Daily Drilling Report, or via a separate cementing report to be submitted as soon as possible following the completion of each cement job:

- a summary of the cement job, indicating whether or not any lost returns occurred,
- the operator's estimate of top of cement, including the basis for this estimate.

The Board is to be notified of any problems or issues arising from an ineffective cement job.

Notwithstanding the above, the Board has defined those circumstances under which it would expect an independent assessment by logging of the hydraulic isolation by cement in cased and/or lined hole sections of a well. In such instances, the logging tool employed should be capable of assessing the integrity of cement bonding to casing and/or to the formation and if capable, identifying channels behind casing that might provide pathways for reservoir fluids.

In accordance with Sections 41 and 46 of the regulations, an operator will be expected to carry out an independent assessment by logging of casing and/or liner cementation for the purpose of assessing hydraulic isolation by cement in:

(a) those exploration/delineation wells where well evaluation could be affected where multiple reservoir zones exist and where formation flow testing is planned to assess the in-situ formation properties of distinct zones;

(b) those development wells where multiple zones or reservoir units exist and where a profile control strategy exists to maximize hydrocarbon recovery, and where optimizing the perforation interval to avail of hydraulic isolation could improve an operator's ability to isolate high water-cut or gas-cut intervals.

- **Well Geophysical Surveys**

Operators should plan to conduct a check shot survey in all exploration and delineation wells. Additionally, the Board may require that a vertical seismic profile (VSP) be conducted where it would further contribute to resolving geoscientific uncertainty. Operators should consult with Board staff early in the planning stages for a well for VSP requirements.

Well geophysical surveys may be necessary in fields under development to supplement existing understanding. The Board would expect operators to conduct surveys, as necessary, in areas of the field where deviation from geoscientific expectations is encountered. The operator should define such areas of uncertainty in its field data acquisition program**,** and address the uncertainty through the well data acquisition program for a candidate well(s).

- **Production Logs**

An operator should list any production logs planned in support of a formation flow test(s) conducted in an exploration or delineation well. Such logs are typically run at the discretion of the operator to access flow contribution of zones or intervals being tested.

An operator of a field under development is referred to the program design guidance provided under Section 6.1.2 of this document in support of a field data acquisition program for expectations respecting production logging in development wells.

Program Submission and Approval:

An operation should follow the following format when preparing its well data acquisition program for logging a well for submission to the Board:

i) The program should be divided into two parts separating those logs run in open hole from those run in cased hole.

ii) Each part should list the suite of logs proposed for the section of the hole being logged or surveyed. Each section of the hole should be identified by indicating whether it is the top, intermediate or bottom-hole section, and by stating the corresponding hole diameter and/or casing size.

A suite of logs is recognized to consist of a single logging run with tools combined and run in the hole simultaneously, or a number of logging runs with tools run in smaller combinations, or run individually. For each logging run, the operator is requested to indicate the auxiliary logs (i.e. GR, CAL, etc.) that will be run in association with the primary measurements.

The logging program, required in support of a “well approval”, will be accepted if it provides for a comprehensive evaluation consistent with the class of well being drilled. In keeping with the intent of Section 11 of the regulations, the Board may require that a particular log or survey be taken if it believes that such a log or survey is necessary. Such a requirement will usually be identified during the well approval process, and would be included as a condition of the approval.

Optional or contingent logs: Where any tool or tool combination being proposed is designated as optional, the operator must state the criteria which will determine whether this tool will be run. In exploration wells, primary open-hole measurements detailed under Section 6.1.1(a) above should be obtained prior to conducting other surveys, e.g. wireline testing, sidewall coring, etc.

Reduced logging effort: An operator may reduce logging efforts where indications from the well justify a reduced logging effort in a particular section of the well. This may apply to formations composed of salt or non-sedimentary rock in an exploration well, or to non-reservoir hole sections in either exploration or delineation wells.

Note: *"Logging while drilling" measurements may suffice to justify and reduce further logging efforts previously planned. An operator should indicate the criteria under which they would conduct a reduced logging program in their well application, otherwise notify a conservation officer by applying for a deviation from an approved logging program.*

Deviation from a well data acquisition program: Where an operator seeks to deviate from a logging program after the well has received regulatory approval, the operator is referred to Section 2.0 of this document - "Notification of a Conservation Officer".

6.1.2 Field Data Acquisition Program

An operator is requested to include the logging program component of a "Well Data Acquisition Program" defined under Section 6.1.1 of this document as part of the "Field Data Acquisition Program" submitted in support of an "Operation Authorization" for a field(s) undergoing development. In making application for a "Well Approval" to drill a well, an operator need only reference the field data acquisition program with respect to the logging component planned for the well.

A field data acquisition program should also include those cased hole logs that would be run in development wells in support of Section 12 of the regulations, or where necessary, during the operational life of a field in support of effective reservoir management.

The following types of cased hole logging are typically recognized for their contribution to the evaluation of a producing pool or field:

- production logging;
- saturation logging; and,
- cement evaluation logging.

Such logging may be necessary to satisfy the requirements for evaluation, monitoring and efficient recovery of petroleum from development wells as set out in Section 6 of the regulations, or as may be required by Section 12 of the regulations in support of workover, suspension or abandonment of wells. The requirement for cased hole logging is not intended to be limited to the above types of logging but may encompass other types of cased hole logging that may be equivalent to, or reflect advances in logging technology.

Sub-sea vs platform wells: The Board recognizes the additional challenge associated with the cased hole logging of sub-sea wells versus platform wells. To this end, in fields being developed sub-sea, the

Board encourages the use of smart well completions and logging during windows of opportunity (i.e. prior to handover to process, or during rig intervention for work over purposes) in an effort to minimize disruption while the field is producing. The Board may nevertheless require logging where well performance indicated through routine well monitoring suggests that waste may be occurring, i.e. lost hydrocarbon recovery.

- **Production Logging**

An operator will be expected to carry out production logging to acquire a flow profile where multiple reservoir zones comprise the completion interval. Such profiling is necessary to assess zonal contribution for production reporting purposes, detect thief zones, identify water breakthrough and to assist in planning work over requirements.

Primary measurements of a production logging tool should include pressure and temperature, downhole flow rate either from or into the completion, and the measurement of the density of fluid flowing from the completed interval. Secondary measurements should include formation natural radioactivity, and internal casing/liner diameter.

An operator will be expected, to carry out production logging on a development well:

- to provide a baseline log where multiple zones comprise the completion interval; and,
- thereafter, as necessary, in response to changes in fluid production, or after any well operation which could affect the productivity, deliverability or injectivity of the completed interval; or,
- where there is reason to suspect that thief zones exist that are affecting injectivity into the well.

A baseline log should be acquired within 2 months of the establishment of stabilized production from, or injection into a well.

- **Saturation Logging**

An operator may be required to carry out saturation logging either in support of production logging, or to provide profiles of fluid saturation in the well. Such profiling may be necessary to provide a basis for tracking flood fronts, identifying reservoir contributing to water influx, and planning and assessing workover strategies.

The logging tool(s) employed should be capable of determining hydrocarbon and water saturation levels behind casing when water salinity is changing, as is typically the case in fields under waterflood.

An operator may be required, to carry out saturation logging on any producing development wells:

- to provide a baseline log following the initial completion of the well; and,
- thereafter, as necessary, during the life of a well to monitor flood front advancement, or to support the design and assessment of work over strategies.

Initial baseline saturation logging should be conducted after well cleanup and prior to water breakthrough in the well. When run to isolate water production, it should be run in association with production logging tools where it could assist in pinpointing water influx.

- **Cement Evaluation Logging**

An operator may be required, in accordance with Sections 41 and 46 of the regulations, to evaluate the quality of cementation of production casing (or liner) during the operational life of the field where indications exist that suggest that the integrity of liner/casing cementation has been compromised, or zonal isolation lost such as to affect the operator's ability to maximize recovery of hydrocarbons from a well in a pool.

Where a cement evaluation log is run to evaluate a suspected loss of hydraulic isolation by cement, the operator is requested to submit its assessment of the cement log to the Board. Where a cement evaluation log was run prior to the initial completion of the well, the assessment of cement integrity by the operator should incorporate both logs. Where the loss of hydraulic isolation by cement is confirmed, the operator of the well may, depending on the impact of the loss of hydraulic isolation, be required to take such remedial action as deemed necessary. This may include a "cement squeeze" over the affected interval.

Program Submission and Approval:

An operator should outline its cased-hole logging program as part of its field data acquisition program submitted in support an "Operations Authorization" for a field approved for development.

Typically, the program should include a high level commitment to cased-hole logging efforts in support of Sections 6 and 12 of the regulations addressing completion, recompletion, work-overs, suspension or abandonment of a well or part of a well. This would include those logs as required where multiple zones and/or pools are co-mingled for production/injection purposes, and those logs that may be run during the operational life of a well in support of work-overs, recompletions or well monitoring.

Issuance of an operations authorization will be given where a field data acquisition program exists and provides for a comprehensive evaluation of a well in respect of the pool in which it is drilled. When filing an application in respect of a specific "well approval" under Sections 6, 11 or 12 of the regulations, the operator need only reference the logging program included under the field data acquisition program. Any additional details respecting logging should be more fully outlined at this time.

Deviation from the field data acquisition program: Where an operator seeks to deviate from a logging program defined under a field data acquisition program, the operator is referred to Section 2.0 of this document - "Notification of a Conservation Officer".

6.2 Operational Guidance

Guidance provided in this section is limited to subject areas that may affect the quality of log data acquired.

(a) Drilling Fluid

The operator should give due consideration to evaluation objectives when selecting the drilling fluid for the well. Logging tools employed should be compatible with, and correct for, the drilling fluid used in the well. Where an operator plans to change its mud system or significantly alter the mud system, the operator should first log the hole section, if altering the nature of the drilling fluid would affect the quality of data acquired.

The constituent components of the mud system used during the drilling of each hole section should be detailed in the “Drilling Mud Report Form”, and submitted to the Board in accordance with Section 3 of these guidelines.

(b) Logging Operations

The following guidance is provided in support of logging operations:

i) Every operator should ensure that logs yield data of good quality by being acquired:
   - as soon as possible after penetrating a potential reservoir to avoid hole deterioration, and to minimize effects of filtrate invasion;
   - at a logging rate that does not exceed service company recommended specifications;
   - before altering the nature of drilling fluid in a manner that would affect the quality of wireline logs;
   - before enlarging the diameter of the hole for the purpose of installing casing; and
   - on floating vessels or MODU’s employing a motion-compensator device, if the vertical motion of the drilling unit is such that the quality of the data would otherwise be adversely affected.

ii) All measurements taken while logging a well should be recorded in digital form, preferably in accordance with **API RP 66 - 'Recommended Digital Log Interchange Standard (DLIS), V-2.00', June 1996**.

iii) A recording increment of approximately every 0.2 metres of tool travel should be maintained as the minimum “wireline” standard for logging a well. Where there is reason to believe that the above recording frequency is insufficient to characterize the complexity of the formation over hydrocarbon bearing intervals, the operator should take such action as necessary (e.g. reduce logging speed) to contribute to improved characterization of the interval.

iv) All measurements taken while logging a well should be recorded with respect to “measured depth”, representing the distance of tool travel from the “point of reference” in accordance with Section 31 of the regulations.

v) Logs acquired while drilling (LWD) should record the frequency of measurement as a function of depth on any log(s) submitted to the Board.

vi) Where "primary" open-hole logs are acquired while drilling (LWD) or by pipe-conveyed (TLC) means, such logs must be depth-tied to the 'primary depth-control log' for the well. Logs that have not been depth corrected to the "primary depth-control log", should be designated and submitted as 'field' logs. Alternatively, a "composite" log of primary open-hole logs may be subsequently submitted where logs are depth-tied to the "primary depth control log" for the well. Where a composite log is submitted, as-acquired logs may be submitted as 'final' logs.

vii) If an operator generates copies of 'true vertical depth' logs, the Board requests that these logs be submitted in accordance with Appendix C2.

viii) To ensure the quality of data, the operator must ensure that each tool run in either open, or cased hole has:

- been calibrated in accordance with recognized practice to ensure the accuracy of measurements taken;
- where practicable, been checked prior to and following each logging run, to verify the validity of the existing calibration; and,
- been run to obtain repeat section(s) (> 50m) over zones where good contrast is present or where hole conditions permit prior to initiating the main logging pass, to verify the repeatability of logging measurements.

ix) All logs acquired in a well should conform with the format defined under **API Recommended Practice 31A "Standard Form for Hardcopy Presentation of Downhole Well Log Data", 1st ed. August 1997** (reaffirmed by API January 2012).

x) Where conditions in a well are such that the taking of any log would endanger the safety of any person, the well or the drilling rig, the operator should defer the taking of that log until the conditions are such that the taking of the log can be done safely.

(c) Well Termination (i.e. Completion, Suspension or Abandonment)

Prior to receiving approval under Section 12 of the regulations to terminate a well (i.e. to complete, suspend or abandon a well or part of a well), the operator must provide such logs and data as may be requested by the Board to assess the presence of hydrocarbons, and any potentially productive intervals before an approval can be issued. The operator may supply these logs in accordance with the reporting requirements for 'Special Circumstances' described in Appendix C2, or by agreed upon means.

6.3 Reporting Requirements

(a) "Operational" Records and Reports

All logs and surveys acquired in a well should be submitted to the Board in accordance with Section 84 of the regulations for "daily reports". This should include the following:

i) One searchable PDF copy of 'field' and/or 'final' 'measured depth' logs, and where they have been generated, 'true vertical depth' logs in accordance with Appendix C2.
ii) one digital copy of all 'measured depth' logs in accordance with Appendix C3;
iii) one digital copy, on USB, SFTP or other medium approved by the C-NLOPB, of the final directional survey;

(b) Well History Report:

The operator is requested to provide a summary list of all logs and/or surveys run in the well as part of the well history report. Searchable PDF and digital copies of "final" logs not submitted previously should be submitted at this time.

Where geophysical surveys are conducted, the following information should be included in the well history report:

i) 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 operators most recent seismic data in the vicinity of the well.

ii) the final report(s) associated with VSP surveys, including:
   - displays of the downgoing and upgoing waves, prior to and post processing, displayed at the same scale as the operator's seismic data in the vicinity of the well;
   - a description of the processing sequence applied to the data; and,
   - any composite logs produced.

iii) one digital copy of all SEGY and ASCII data on USB, SFTP or other medium approved by the C-NLOPB, associated with each well geophysical survey:

Please note the electronic copy requirements defined in Section 2.1(4) of this document respecting submission of the above reports in support of the well history report.

The Chief Conservation Officer should be informed of any anticipated delays in the submission of any of the above information when submitting the well history report. In such cases, this information should be submitted promptly upon completion of this work.

(c) Field Data Acquisition Program

One searchable PDF and one digital copy of each cased-hole log run in support of a field data acquisition program should be submitted to the Chief Conservation Officer within 60 days of running the log. The submission of digital data should be made in the form and manner indicated in Appendix C3.

Note: *A tabular listing of all logs run in a development well during the year should be provided in the* ***"Annual Production Report"*** *required by Section 86 of the regulations.*

7.0 Testing and Sampling of Formations

Section 51 of the regulations requires an operator to ensure that every formation in a well is sampled or tested to obtain fluid flow and reservoir pressure data where an indication exists that the result of such a sample or test would contribute substantially to the evaluation of the formation.

7.1 Program Design

7.1.1 Well Data Acquisition Program

The operator should outline its program for the testing and sampling of formations in a well as part of the well data acquisition program required by Section 11 of the regulations in support of the application for a well approval to drill a well.

The following types of investigations are possible: (a) pressure-depth surveys typically conducted by wireline, or LWD conveyance in open hole, and limited to small scale investigations confined to the near wellbore; and (b) formation flow testing conducted in the cased hole, and designed to carry out large scale investigations beyond the influence and contamination of the near wellbore. Both approaches present distinct advantages and limitations with respect to well evaluation.

(a) Pressure-Depth Surveys

An operator will be expected to survey those open hole sections of a well in which indications of porous and permeable reservoir rock exist. An operator should plan to conduct a pressure-depth survey as part of its well data acquisition program required in support of a well approval for an exploration and/or delineation well. In development wells, an operator may limit its survey to those intervals targeted for development or those intervals that offer potential for development.

Recent advances in logging while drilling technology has meant that pressure-depth surveys may be acquired while drilling (LWD) in lieu of conventional wireline logging or TLC conveyance post drilling. Limitations with LWD based tools currently preclude the capturing of fluid samples, and may limit the usefulness of these tools in exploration or delineation wells.

A survey should plan to test all potential reservoir intervals to confirm the existence of porous and permeable reservoir, and to record pore pressure. The operator should take multiple measurements over an interval where sufficient interval thickness permits to:

i) verify the existence and quality of permeability over the porosity range evident within the interval for the purpose of establishing an effective porosity cutoff for productive reservoir; and,

ii) establish a pore pressure gradient over the interval for the purpose of:
- identifying in situ fluid types;
- verifying the existence of fluid columns;
- identifying barriers to vertical pressure communication;
- identifying isolated sands or sand stringers;
- identifying and/or estimating fluid contacts;
- studying regional pressure regimes;

and, in development wells take sufficient measurements for the purpose of:
- determining pool or zone pressures prior to completion;
- verifying inter-well sand continuity;
- assisting in pool or zone designations; and
- enabling material balance assessments.

Note: *In an exploration or delineation well, an operator should plan to obtain samples of in-situ hydrocarbons and formation waters where such opportunities exist. Fluid samples acquired are subject to the submission requirements of Section 53 and 55 of the regulations.*

(b) Formation Flow Testing

Section 52 of the regulations defines the requirements for formation flow testing of wells in relation to exploration, delineation and development wells. Guidance is provided below in respect of testing requirements associated with the various class of wells.

- **Exploration Well**

An exploratory well is defined by the Act as a well drilled on a geologic feature on which a significant discovery has not been made. Under Section 52(2) of the regulations, there is no regulatory requirement to conduct a test in an exploration well, i.e. the decision to test rests solely with the operator of the well.

Attention: *Under the requirements of the Act, a formation flow test is required on the well for which an application for* ***"Significant Discovery Declaration"*** *is made.*

While the testing of an exploration well is not required, an operator should nevertheless indicate its intent respecting testing in the well data acquisition program submitted in support of the application to drill a well. Where the intent is to conduct a formation flow test on an exploration well, the operator may:

i) later decide to abstain from testing and abandon the well; or,

ii) defer testing, by suspending the well in a manner that would allow the well to be re-entered and tested at a later date.

Note: *An operator may defer testing for operational reasons, such as allowing for a necessary weather window or for safety reasons, or simply to allow for proper planning of the test in light of uncertain well results, or where analysis of core, logs or fluid samples would contribute to further defining test objectives in respect of reservoir uncertainties.*

Written confirmation of an operator's decision respecting testing should be provided to the Chief Conservation Officer as soon as possible on reaching the proposed TD for the well.

- **Delineation Wells**

In respect of a delineation well(s), the operator may conduct formation flow tests at their discretion, to further appraise the discovery and resolve uncertainty.

Note: *For the purpose of Section 119 of the Act respecting the disclosure of information, the Board's Chief Conservation Officer will classify wells as "exploration" until such time as a declaration of significant discovery respecting an exploration well drilled on a geologic feature has been made by the Board. In this respect, one or more exploration or delineation wells may be necessary to delineate a geologic feature and/or the extent of the hydrocarbon accumulation discovered.*

Notwithstanding the legislative requirement for formation flow testing in support of an application for "Significant Discovery Declaration", the Board may require in accordance with Section 52(3), that an operator conduct a formation flow test in a delineation well(s), if there is an indication that such a test would contribute substantively to the geological and/or reservoir evaluation. The Board would typically expect formation flow test(s) in support of the appraisal of a field, or in support of a Development Plan Application to address one or more of the following objectives:

- assess the flowing potential of prospective pay intervals encountered;
- evaluate in-situ flow behaviour and completion efficiencies to identify sustained deliverability or injectivity potential and to maximize inflow performance capability;
- address flow assurance uncertainties in respect of fluid and/or reservoir properties, reservoir compartmentalization and/or sub-seismic faulting;
- enable scale-up of log derived porosity/permeability relationships to grid sized properties in support of simulation studies of proposed depletion schemes;
- support well planning requirements and/or well spacing studies;
- obtain "representative" in-situ fluid samples of oil, gas or gas-condensate systems;
- optimize facility requirements in respect of fluid properties and inflow capabilities.

An operator should plan for and conduct testing in select delineation wells where such testing could resolve technical and/or economic uncertainties highlighted above 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 Board Staff prior to drilling.

Note: *An operator may defer formation flow testing in any delineation well by suspending the well until an assessment is made of the extent and potential significance of reservoirs encountered, or for planning purposes respecting test design.*

- **Development Wells**

The operator of a field being developed is referred to Section 7.1.2 - "Field Data Acquisition Program" for guidance respecting formation flow testing in development wells.

Program Submission and Approval:

The operator should indicate its intent to conduct a formation flow test on an "exploration or delineation" well in its well data acquisition program submitted in support of Section 11 of the regulations. In order to facilitate an early review of a test program, the operator will be expected to engage with Board staff as soon as possible following ADW approval. Submission of the program in its final form including specifics respecting the interval to be tested should be made at least 5 working days before commencement of testing operations. The program should include:

i) a description of each interval to be tested, including:
   - measured depth to the top and base of the interval to be perforated;
   - 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 anticipated, including estimates of fluid properties where available.

ii) details of the proposed equipment pressure tests, and other safety precautions to be taken prior to and during testing in accordance with guidance provided under Section 34 of the regulations;

iii) 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;
   - 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; and,
   - data gathering and reporting procedures.

iv) a description of the equipment to be utilized in the test program, including:
   - a diagram or makeup of both the bottom hole test string assembly and landing string assembly, including a description re the functioning of each tool employed in the assembly;
   - specifics associated with all proposed downhole gauges, e.g. location in string, sampling frequency, accuracy, resolution and provision for measurement verification; and,

- a schematic of surface equipment showing the flow paths for produced fluids, i.e. gas, oil, condensate and produced water, including the flow path of fluids employed in assisting production i.e. artificial lift operations.

The operator is referred to Section 7.2 of this document for operational guidance in respect of test programs conducted in support of testing "exploration and delineation" wells.

Approval Process and Witnessing a Test: As part of the approval process, the operator may be requested to meet with the Board's technical staff to discuss the test, and address any questions or concerns that may exist. The Board, or the operator, may at this time request that one of the Board's conservation officers witness a test that may provide the basis for a "Significant Discovery Application".

7.1.2 Field Data Acquisition Program

Guidance in respect of testing and sampling of formations in support of a field data acquisition program is limited to the formation flow testing of approved development horizons as defined in the Development Plan Application, and any such testing as may be carried out over secondary horizons not currently approved for development. Pressure-depth surveying of development wells should be defined as part of the well data acquisition program submitted in support of the application for well approval to drill a development well.

Section 52(1) of the regulations requires Board approval of a formation flow testing program before a development well is put into production or subject to a well operation that might change its deliverability, productivity or injectivity. An operator may outline its program for formation flow testing of development wells as part of its field data acquisition program required in support of the issuance of an "Operations Authorization" for the field. Such testing typically includes both "production testing" and "injection testing" of development wells. The program for testing wells must be approved by the Board before a well(s) can be placed into production.

Standard Test Program: An operator is encouraged to reduce the number of approvals respecting the testing of development wells by developing and referencing a "standard test program" for the testing of its wells. Where a standard test program has been provided in the field data acquisition program, an operator need only reference this program when completing a well. Otherwise, an operator should submit for the Board's approval the testing program specific to the subject well.

An operator would be expected to carry out a formation flow test in a development well:

i) upon initial completion of the well; and,
ii) following a well operation that could change either the productivity, deliverability or injectivity of the well, e.g.:
    - stimulation of the well through acid or fracturing treatments;
    - re-completion, and/or isolation of any portion of a well's completion interval where post well operation performance has not met defined pre-job expectations.

To this end, the Board appreciates that production or injection stabilization is preferable prior to conducting such testing. Testing following the initial completion of the well under i) above should be conducted within 2 months of establishing stabilized production from or injection into a well, and where well performance dictates within a reasonable timeframe following the well operation described under ii) above.

Program objectives required in accordance with Section 52(1) of the regulations should include for producing wells:

- establishing the characteristics of the reservoir;
- acquiring data on the deliverability or productivity of the well; and,
- obtaining representatives samples of reservoir fluids;

and for injection wells:

- establishing the characteristics of the reservoir;
- acquiring data on the injectivity of the well.

Note: *In both producers and injectors, shut-in duration following flow or injection periods should be sufficient to permit the determination of average reservoir pressure in support of the "Annual Pool Pressure Survey".*

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 comingled test where supported by cased hole production logging.

For 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 re 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: A field data acquisition program should outline the operator's approach to testing prospective hydrocarbon bearing reservoir intervals not currently targeted for development. This would likely occur in the absence of other strategies for reservoir appraisal, and would need to be addressed prior to abandonment or reuse of the well, or part of the well, in which prospective interval(s) were identified. This may include secondary horizons that may, or may not have been identified as part of the Development Plan Application.

Note: *Given that the primary focus of development wells is the exploitation of approved development horizons, the Board would limit any evaluation requirements respecting the testing of secondary horizons to coincide with requests for abandonment or reuse of the wellbore. The operator should be prepared to test secondary horizons to effect an appraisal of the significance of these horizons prior to abandonment or reuse of the well. To this end, testing considerations should address the uncertainties* *identified typically for delineation wells. The Board recognizes the operator's need to customize test design specific to the well and situation.*

Program Submission and Approval:

A "standard" test program submitted in support of a field data acquisition program should outline the objectives that will be followed in testing producers and injectors including the equipment and procedures to be used and followed in conducting the test. The program should list the flow/injection and shut-in periods upon which test objectives will be realized.

In wells where an operator decides to deviate from a standard testing program, the operator should submit a test program in support of the "well approval" specific to the objectives and uncertainties as identified. The need to deviate from a standard test program is recognized by the Board, and could typically apply to any development well(s) where well results dictate that specific test objectives address reservoir related uncertainty.

Note: *Specific or customized test programs would typically apply to those wells where requirements exist to evaluate secondary reservoirs prior to abandonment of a well, part of a well, or where reuse of the well by sidetracking may be required.*

Approval in respect of the formation flow test program will be given through the "well approval" process for the well.

7.2 Operational Guidance

Except where indicated, the following guidance is provided in relation to the conduct of formation flow testing on "exploration" or "delineation" wells to promote consistency in meeting regulatory requirements.

(a) Safety

In accordance with the Safety Plan submitted in support of an Operations Authorization, an operator will be required to hold a safety meeting immediately prior to conducting a formation flow test to review testing procedures and discuss emergency response measures.

For safety and environmental reasons, no formation fluids shall flow to surface, or be circulated to surface at the commencement of a test until 'daylight' hours are reached. Subsequent secondary flows associated with the same test are permitted during hours of darkness where 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. To this end, the operator's policies on this matter should be clearly highlighted within the testing program submitted to the Board.

(b) Equipment Requirements

An operator is referred to Sections 34 and 36 of the Drilling and Production Guidelines for guidance and standards applicable to "Formation Flow and Well Testing Equipment" and "Well Control" in respect of formation flow test conducted on exploration and delineation wells.

Note: *It is emphasized that the equipment used in conducting a formation flow test on a well must be capable of properly evaluating the interval or formation in question. Adequate tankage and flaring capability must exist to permit the temporary storage and disposition of produced fluids in accordance with design flow rates and durations of flow necessary to meet test objectives. Operators should be prepared to address any operational difficulty that may be reasonably foreseen.*

As stated under program design, an operator may defer the testing of a well where doing so would allow for proper planning of the test. This would include, for example, being prepared to assist using artificial lift technology to effect the flow of heavy oil to surface where test objectives would otherwise be jeopardized by an inability to maintain flow. In this respect, the operator should first make every effort to maximize data quality through closed chamber testing techniques where evidence of heavy hydrocarbons or limited inflow performance exists. This approach would be expected prior to any attempt to flow the well conventionally, or before introducing artificial lift techniques to assist flow.

(c) Fluid Sampling Requirements

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 regulations. The collection and analysis of samples should be in accordance with:

- **API RP 44 "Recommended Practice for Sampling Petroleum Reservoir Fluids", 2nd ed., 2003**;
- **API RP 45 "Recommended Practice for Analysis of Oilfield Waters", 3rd ed., 1998, reaffirmed January 2012**.

Notwithstanding the operator's requirements for fluid samples, the Board requires that the operator collect for submission to the Board the following samples:

Exploration/delineation wells - 1 set of atmospheric samples consisting of samples of each liquid produced (oil, or condensate and water) from each test conducted. Each sample should be at least of 4 litre capacity. Samples of produced gas need not be collected unless specifically requested by the Board.

Development wells - 1 set of samples, as above, in respect of formation flow tests conducted on "secondary reservoirs" being appraised to assess development potential.

(d) Testing of Exploration and/or Delineation Wells

An operator is referred to Appendix C4 for guidance related to the flow and shut-in periods when conducting formation flow tests on exploration, and/or delineation wells.

As a minimum, a test should consist of those periods indicated by i), ii) and iii) below:

i) initial flow and shut-in periods;
ii) cleanup flow period;
iii) primary flow and shut-in periods;
iv) sampling flow period; and,
v) secondary flow(s) and associated shut-in periods.

The sampling flow period (iv) along with the secondary flow and shut-in periods (v) are considered optional and to be conducted at the discretion of the operator. The Board recognises that minor deviation from suggested period durations indicated in Appendix C4 may be warranted dependent upon the specific reservoir response and stated test objectives. The operator is requested to review the following regulatory expectations respecting the above subject areas when preparing its test program.

i) Initial Flow/Shut-in Periods:

The initial flow and shut-in periods should be designed to relieve through minor flow, any interval supercharging that may have resulted from the drilling or completion process, and through shut-in, provide the basis for determining initial reservoir pressure.

Shut-in duration should be of fixed duration, as suggested in Appendix C4, to minimize any uncertainty that may arise in the estimation of initial reservoir pressure.

ii) Cleanup Period:

Achieving cleanup is considered essential to realizing test objectives. The duration of this period will be defined by the time required to displace cushion, completion fluids and invasion fluids from the test string and establish the stable flow of in-situ formation fluids at surface. This is recognized to take anywhere from a few minutes for high-rate wells, to several hours for low-rate wells.

Note: *Where cleanup cannot be achieved due to operational difficulties, the influx of heavy oil, or to suspect wellbore damage, the operator is encouraged to retest the interval employing corrective procedures or alternative equipment suited to the task. This would include assisting flow where practicable, should conventional testing methods prove to be inadequate in effecting cleanup of the well. Where a test is terminated during cleanup because of inferred poor or non existent in-situ productivity, the operator should nevertheless attempt to capture fluid samples either downhole, or upon reverse out of string contents, where indications support the influx of in-situ formation fluids into the test string.*

iii) Primary Flow and Shut-in Periods:

The primary flow and shut-in periods should provide the basis for the acquisition of representative fluid samples and data necessary to assess flow behaviour and derive reservoir flow characteristics.

The primary flow period should represent a period of rate stabilization during which time the operator is encouraged to stabilize flow in accordance with the guidance provided in Appendix C4 and C5. A minimum of 4 hours stabilized flow is suggested with a maximum flow duration of 24 hours being recommended. While changes in flow rate are discouraged, any change in rate imposed during this flow period should be followed by a minimum period of 4 hours stabilized flow prior to shut-in.

Data acquired during the primary shut-in period should permit an assessment of flow behaviour from which the determination of reservoir characteristics may be derived. Uncertainty associated with interpretation will be minimized where shut-in follows a flow period producing at stabilized rate. Shut-in provides the basis for assessing an interval's pressure recovery to produced volumes.

iv) Sampling Flow Period:

This period should be distinct and separate from other flow periods where quality in-situ fluid samples are required. The period should normally follow the primary shut-in period, and precede the pursuit of any secondary flow objectives. Sampling may precede the "Primary Flow and Shut-in Periods" if samples are critical to test objectives.

The operator should employ downhole fluid sampling procedures to acquire PVT quality samples, where samples obtained at surface are felt to be unsatisfactory for PVT purposes. The collection and analysis of samples should be in accordance with **API RP 44 "Recommended Practice for Sampling Petroleum Reservoir Fluids", 2nd Edition, 2003** and **API RP 45 " Recommended Practice for Analysis of Oilfield Waters", 3rd Edition, 1998, reaffirmed by API January 2012**.

v) Secondary Flow and Shut-in Periods:

The secondary flow and shut-in periods are considered optional periods available to the operator to address objective(s) that fall outside the scope of the primary flow and shut-in periods. Typical secondary period objectives may include, but are not limited to:

- the assessment of inflow performance of oil wells or deliverability performance of gas wells;
- the demonstration of maximum flow capability of the interval being tested;
- the investigation of reservoir limits or boundaries for the purpose of reserves determination;
- the investigation of interval productivity following stimulation; and,
- the assessment of injectivity capability.

The operator is referred to the **ERCB Directive 034 "Theory and Practice of the Testing of Gas Wells (SI Units)", 4th ed. 1979** and to **ERCB Directive 040, "Pressure and Deliverability Testing Oil and Gas Wells", December 2006** in respect of testing oil and gas wells.

Note: *As indicated in Appendix C4, the duration for secondary flow should not exceed 4 days, or such duration as approved by the Chief Conservation Officer and Chief Safety Officer. This limitation is intended to minimize prolonged environmental or safety risks, and prevent any confusion* *between the secondary objectives of a formation flow test and the broader, longer term objectives of an "Extended Formation Flow Test" as defined under Section 140.2 of the Canada-Newfoundland Atlantic Accord Implementation Act.*

(e) Downhole Shut-in and Real-Time Pressure Monitoring

The beneficial contribution of downhole shut-in and real-time pressure monitoring to the conduct of a test, and to the quality of data received is recognized particularly in the testing of exploration and delineation wells. The Board encourages the use of this technology and will accept real-time monitoring as the basis for deviating from an approved test program. Such deviation might include changes that affect either period durations, or drawdowns as approved. Where such monitoring is not employed, an operator should adhere to durations approved in the test program.

Note: *The inclusion of a downhole test tool to effect downhole shut-in is intended for evaluation purposes to minimize the effects of wellbore storage effects that would otherwise mask the detection of near wellbore boundaries or the onset of radial flow region. This tool is considered to be "discretionary" and if employed should, in the event of tool failure, be designed to fail in an "open position" to enable continuation of the test via surface shut-in at the choke manifold. This tool should not be confused with the broader requirement of Section 34(2) of the regulations for a downhole safety valve (DHSV) above the packer and which, by design, should fail in a "closed position".*

(f) Downhole Pressure/Temperature Gauges

In exploration and delineation wells, two categories of end use for downhole gauges are recognized: gauges employed for the purpose of reservoir evaluation, and; gauges employed for trouble shooting purposes.

The operator should ensure that electronic gauges are used where a gauge(s) is being employed for measuring reservoir pressure and temperature for pressure analysis purposes. The gauge selected should be suited to the operational environment, planned test duration, and the anticipated accuracy and resolution demands expected, based upon available knowledge of reservoir quality and fluid properties.

Gauges employed for trouble shooting purposes need not be electronic but should nevertheless be suitable for the required task (see Appendix C6). Such gauges are necessary to verify test packer integrity, as well as the proper functioning of the downhole shut-in tool employed.

The Board requires that:

i) all gauges employed are calibrated or checked for accuracy and repeatability against a reference gauge prior to, and immediately following a formation flow test; and,

ii) adequate gauge redundancy exists to validate data and negate any affects of gauge failures.

The results of gauge calibration or checks must be recorded and dated. The reference gauge employed must have its calibration traceable to an international standard.

An operator is referred to the guidance provided in Section 8.2(a) of this document respecting the use of permanent downhole gauges typically run in development wells as part of a well(s) completion. Appendix C6 provides a cross-section of the various types of gauges in use.

7.3 Deposition and Analysis of Fluid Samples

Section's 53, 54 and 55 of the regulations detail the requirements for the deposition and analysis of fluid samples from a well.

(a) Deposition of Samples from Site

All pressurized samples are to be transported in the appropriate Department of Transportation (DOT) approved containers. Atmospheric samples should be transported in suitable containers that prevents loss or deterioration of the sample.

Samples should be delivered to the Board within 60 days of when the sample was acquired, see Appendix B1. All sample containers must be suitably labelled or identified with the well name, field, test #, interval, and source as well as the nature of the sample, i.e. oil, gas, gas condensate, water, or combination thereof.

(b) Analysis of Fluid Samples

Analysis of fluid samples should be in accordance with **API RP 44 "Recommended Practice for Sampling Petroleum Reservoir Fluids", 2nd Edition, 2003** and **API RP 45 " Recommended Practice for Analysis of Oilfield Waters", 3rd Edition, 1998, reaffirmed by API January 2012**.

7.4 Reporting Requirements

(a) Operational Records and Reports

- **Pressure-Depth Surveys**

The results of a pressure-depth survey should be submitted to the Board in the form of a log or report as required by Section 84 of the regulations and by Section 7.3(a) of this document. The log should include:

i) A summary section, or log header, consisting of a table reporting results from survey stations, and a corresponding remarks column. The table should provide a brief summary of all tests conducted noting the depth, success of test, the result as to reservoir pressure, and whether a fluid sample was captured. All pressures noted in this table should be corrected for temperature and reported in absolute pressure.

Note: *Remarks by service company personnel should include the serial number and make of the gauge employed, and whether pressures reported in the log header were temperature corrected and reported in absolute pressure. Remarks should also indicate the status of corrections, if any, reflected in individual tests results which follow in the main body of the log.*

ii) The main body of the log should consist of the individual records of tests conducted in this survey. Each test record should capture the initial hydrostatic pressure of the mud column at test depth, the setting of the tool, the pretest and shut-in periods as well as the final hydrostatic pressure upon completion of test. The specifics of any effort to obtain fluid samples should also be noted. Where fluid properties of samples taken by wireline tools have been determined, the operator should provide a description of fluids recovered, noting volumes of recovery and fluid properties, i.e. API gravity of oil, and water resistivity at measurement temperature. Pressures recorded during the test should be printed on this record at appropriate increments to adequately characterize the test.

iii) The trailer section of this log must contain the recent calibration history of the gauge. This should include the master calibration record for the gauge.

Please refer to Appendix C2 and C3 for submission requirements for pressure-depth surveys.

- **Formation Flow Tests**

In accordance with Section 84 of the regulations, the operator of an “exploration or delineation” well is requested to submit by email or other agreed upon means, daily records associated with any formation flow test conducted. This should include:

i) the event history documenting the time of any action taken which may have affected the test or the interpretation of test results;

ii) flow rate data corrected to standard conditions noting correction factors, choke settings and the corresponding pressure/temperature data at the wellhead and at the test separator;

iii) total volume of fluid recovery and the volumes associated with each fluid produced;

iv) all relevant data associated with the acquisition of fluid samples; and,

v) at the conclusion of the test, a complete set of pressure/temperature data from all downhole gauges along with gauge specifics, i.e. maker, model number, serial number, depth of measurement, date of calibration and the results of pre and post test calibration checks.

Daily records associated with i) through iv) above should be submitted to the Board as a searchable PDF file(s), or preferably in digital format as Excel or ASCII formatted files.

Pressure/temperature data referred to in (v) above should be submitted immediately upon conclusion of the test in digital form as an Excel file or space delimited ASCII file. Preliminary submission of gauge data to the Board may be by email, or alternatively on USB, SFTP or other medium approved by the C-NLOPB. 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.

(b) Well History Report

The operator of an "exploration or delineation" well should provide a brief summary of the results and any reports associated with formation flow test(s) conducted. This would include the required copies of:

i) reports submitted to the operator by service companies and consultants, where applicable, relevant to the conduct of formation flow tests conducted; and,

ii) any fluid analysis reports of oil or condensate, gas and water samples collected at surface facilities or by downhole sampling methods.

Please note the submission requirements defined in Section 2.1(4) of this document for well history reports.

Additionally, the Board requests that fluid analysis reports referenced in ii) be submitted where applicable, in digital format as an Excel file, or a space delimited ASCII file.

(c) Field Data Acquisition Program

Unless otherwise noted in the approval issued for an ADW, formation flow test reports associated with tests conducted on producers and injectors as defined under Section 7.1.2 of this guideline should be consolidated under one submission and submitted once annually as part of the "Annual Production Report".

Note: *This change is intended to streamline reporting to the Board thereby waiving the previous requirement for submission of the report on conclusion of the test. This applies to formation flow tests carried out upon initial completion of a well, and where applicable those tests following re-completion of a well. Exceptions may include formation flow tests conducted on secondary horizons being evaluated to access development potential, or those "extended" formation flow tests carried out over targeted horizons.*

A formation flow test report should contain all relevant information relating to the conduct, results or analysis of the test including event history, relevant rate history and pressure date including gauge specifics and a summary of fluid samples that may have been taking in support of the test. Pressure data should be submitted to the Board with the report in digital form as an Excel File, or space delimited ASCII files on USB, SFTP or other medium approved by the C-NLOPB. 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 blanks not commas.

8.0 Pool Pressure Measurements and Surveys

Section 6(i) of the regulations requires that a field data acquisition program allow for sufficient pool pressure measurements for a comprehensive assessment of the performance of development wells, pool depletion schemes and the field.

The guidance provided in this section has been obtained in part from **ERCB Directive 040, "Pressure and Deliverability Testing Oil and Gas Wells", December 15, 2006.**

8.1 Program Design

The operator of a field will be expected to:

- determine for each producing well, the initial pressure of the pool or zone upon completion, prior to commencing production from the interval; and,
- carry out an "Annual Pool Pressure Survey" as part of its field data acquisition program required in support of the Operations Authorization issued by the Board.

(a) Pool Pressure at a Well upon Completion

This measurement provides the baseline for initial pool pressure. It also enables the identification and delineation of that pool in subsequent development wells, and within infill wells, provides a basis for assessing drainage area and recovery efficiency.

The initial pressure of the pool should be based upon the pressure-depth survey for the well, as described in Section 7.1.1(a) of this guideline, corrected to datum depth. The operator should address any notable disagreement between this pressure, and the pressure reported as part of well backflow, or the initial formation flow test conducted for the well.

Where a pressure-depth survey was not conducted, the initial pressure of the pool should be determined:

- following well backflow or cleanup and prior to placing the well into service; or,
- as part of the initial formation flow test where this test is conducted prior to placing the well into service.

The reference to "placing the well into service" is considered the point in time after completion of the well when the well is handed over to process for production or injection purposes.

(b) Annual Pool Pressure Survey

The operator should outline its strategy for the annual pool pressure survey as part of its field data acquisition program.

The Board acknowledges the operator's need to minimize losses in production when complying with the requirement for an annual survey. Consequently, all wells need not be part of the annual pressure survey. Furthermore, it is expected that the operator execute its survey around both scheduled and unscheduled well downtime.

The following criteria should be considered by an operator when detailing the strategy for conducting annual pool pressure surveys:

i) wells surveyed should provide an accurate indication of the pressure distribution within a pool, and for the field;
ii) wells located in high and low pressure areas in which a pressure maintenance scheme exists should be surveyed each year;
iii) pressure sources such as injection wells should be included in the survey;
iv) wells not surveyed for the past 3 years should be considered for survey; and,
v) wells located in areas where pressure levels, pool boundaries and pool continuity are uncertain, or where anomalous pressure trends exist, should be surveyed.

Wells which are recognized as being good candidates for surveying include:

- wells in which an open-hole pressure-depth survey was conducted;
- wells subject to a formation flow test, i.e. either a producer or injector following initial completion, or in response to a workover;
- suspended wells; and,
- wells subject to downtime.

Results for the annual pool pressure survey(s) conducted for the field should be submitted to the Board as part of the Annual Production Report required under Section 86 of the regulations. The submission should contain the proposed program for the upcoming year reflecting on the strategy outlined in the field data acquisition program and the wells surveyed in the previous year(s). The proposed program should include:

i) the planned survey date;
ii) each pool's datum depth;
iii) a list of the wells or alternates to be included in the survey;
iv) the type of survey planned for each well (static gradient, build-up or fall-off survey) including the shut-in time prior to conducting the survey; and,
v) the details of instrumentation employed in the survey, including gauge calibration details.

The Board recognizes the flexibility needed by operators in conducting such surveys. To this end, the Board will accept the valid results of any survey conducted during this time, provided the well(s) concerned were included in the survey program, and were subsequently deemed to be acceptable by the Board as part of the overall pool survey. Where permanent downhole gauges are used (i.e. see Section 8.2(a) below *Recommended Practices for Gauges - Use of Permanent Downhole Gauges)*, the Board 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 Board being satisfied that it provides for the accurate determination of the static pressure in the pool.

8.2 Operational Guidance

(a) Recommended Practices for Gauges

The following practices, which have been adopted from **ERCB Directive 040, 'Pressure and Deliverability Testing Oil and Gas Wells',** are recommended when conducting a pressure survey:

i) A minimum of two (2) gauges should be run in tandem as part of every survey as a check on the performance of the gauges, and to improve the reliability of pressure measurements taken.
ii) To minimize the introduction of errors, the same gauges should be used where multiple surveys or tests are to be conducted in a well.
iii) All pressure measurements should be made to the reference depth for all measurements as agreed to by the Chief Conservation Officer and the operator.
iv) Gauges are to be run at, or close to the mid-point of the contributing interval in the case of vertical or deviated wellbores, or in the case of horizontal wellbores as close as possible to the point where the well goes horizontal. Where gauges cannot be placed as recommended, the operator should establish the fluid pressure gradient in the wellbore.
v) When a gauge is returned to surface, a measurement should be taken as to the amount of stretch that resulted in the wireline during the survey. Wireline stretch should not exceed the manufacturer's tolerances provided as a function of run depth. Where these tolerances are exceeded, conditions that may have caused slip or elastic deformation of the running medium should be reported.
vi) The maximum temperature thermometer should be read and the reading recorded after each gauge has been retrieved from the well.
vii) Casing and tubing pressures should be read during the survey and measurements recorded. These readings should be taken with a dead weight tester or with a gauge of similar accuracy and reliability.

Measurement Reliability:

The operator should ensure that all pressure gauges run in a well have been calibrated under anticipated operating conditions and, where practicable, checked against a dead weight tester prior to and following its use in the field. The operator is requested to retain the records of any gauge calibration or gauge check for a period of 24 months following submission of its annual survey and to make these records available to the Board upon request.

Where a dead weight tester is employed, it is required that this device be checked or calibrated against an acceptable primary standard. This comparison is required before the tester is put into use and, thereafter, on an annual basis. The primary standard employed should be traceable to a national standard.

A correction table should be established where differences in readings between the dead weight tester and primary standard exceed 0.1 percent. This table should then be employed to further correct measurements recorded by downhole gauges.

Use of Permanent Downhole Gauges:

Supporting documentation detailing the specifications and reliability of permanent down hole gauges proposed for use in development wells for pressure measurement and pool pressure survey purposes should be submitted to the Chief Conservation Officer for review and acceptance prior to their installation. This information should be detailed as an appendices within the "Field Data Acquisition Program".

Permanent downhole gauges should be checked for measurement reliability whenever indications exist which warrant such action. To this end, an operator may be required where conditions permit, to run into the hole with a gauge that will permit an assessment of the reliability (accuracy, repeatability) of a permanent downhole gauge, and establish any corrections for "drift" that may be necessary.

(b) Initial Completion or Re-completion of a Well

Where survey data results from initial completion or re-completion of a well either on shut-in of the well following backflow (i.e. cleanup) or as a consequence of formation flow testing conducted in support of the initial production test, or initial injection test or on re-completion of the well, the following criteria should be satisfied:

i) In wells undergoing initial completion, the shut-in duration associated with the backflow or cleanup of the well, should be adequate to extrapolate reservoir pressure to fall within one percent of wireline pressures at datum depth.
ii) In wells undergoing initial completion where the initial formation flow test is conducted, the pressure to be used in the survey should be based upon extrapolated pressures from two shut-in periods that fall within one percent of each other.

iii) In wells undergoing re-completion, where the well has been under production or injection for some time, the pressure to be used in the survey should, after extrapolation, fall within five percent of the last pressure survey conducted for that location.

8.3 Reporting Requirements

(a) Annual Pool Pressure Survey Report

The operator should submit the report as part of the "Annual Production Report" providing summary analysis of reported pressures, together with an isobaric map of these pressures corrected to datum depth. The operator is referred to Appendix C7 for the procedure for correcting pressures to datum depth. The annual production report for the year ending on December 31, should be submitted as a searchable PDF to the Board not later than March 31 of the following year.

(b) Pressure Data

Where 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 re-completion 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 C-NLOPB 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).

9.0 Fluid Sampling and Analysis

An operator should outline in its field data acquisition program, its plans for the fluid sampling of wells, and pools in a field during the operational life of the field to ensure that a comprehensive geological and reservoir evaluation can be made consistent with good resource management practice.

9.1 Program Design

A field data acquisition program should plan for the fluid sampling of a pool at the following intervals:

- upon completion of a well in a pool;
- annually, for the purpose of determining the composition of the fluids in the pool; and,
- where water is produced from a well, to determine the composition and source of the produced water.

The fluid sampling and analysis program will be accepted if the program proposed by the operator satisfies, or is equivalent to, the expectations provided in the following guidance.

(a) Sampling at Well Completion

The operator of a development well will be expected to collect and analyze fluid samples upon initial completion of the well in a pool and, thereafter, upon recompletion of the well in any new pool.

Samples should be taken during the initial formation flow test by subsurface means where the taking of surface samples would be unsatisfactory for analysis purposes. Samples collected at surface should be recombined to initial reservoir conditions. Samples obtained will establish the baseline for subsequent monitoring of the well for changing fluid composition.

(b) Sampling Annually

Once production from a pool is initiated, the operator will be expected to obtain and analyze samples of oil, gas and water collected at surface from a sufficient number of wells completed in that pool to determine the composition of fluids. This analysis should be conducted once every 12 months, or more frequently when there is reason to believe that the composition of fluid produced from the pool has changed.

Where a select number of wells in a pool are sampled, the criteria for well selection should ensure that the resulting analyses provide an accurate indication of the composition of fluids in the pool. For this purpose, wells in areas where fluid properties are known to vary, or are uncertain, should be sampled. Similarly, wells omitted from sampling programs in previous years should be given priority. Generally, the following producing wells are considered good candidates for sampling:

- wells subjected to a formation flow test;
- wells having experienced a significant change in either the composition of petroleum fluids, or in gas/oil ratio, or water cut; and,
- wells in which production is not commingled.

An operator should collect samples from producing wells, during routine allocation tests for proration purposes, and at any time for injection wells, by sampling the injection fluid streams.

Sampling of gas injection wells should be conducted where knowledge of injection gas composition is critical to a depletion scheme, and in water injection wells where quality control of injection water is required. Fluid injection streams should be sampled at the injection manifolds, or where practicable, at individual wellheads.

An operator should acquire fluid samples and carry out the appropriate analyses whenever there is reason to believe that the composition of a fluid produced from or injected into a pool has changed. Samples should be taken following stabilization of well conditions, but in any event, not later than 1 month after changing conditions are first observed.

- **Sampling of Group and End Use Streams**

An operator should sample and analyze the following group and end use fluid streams as part of the annual sampling program where sampling would contribute to either the evaluation of the pool or field, or assist in environmental monitoring:

i) group hydrocarbon production going to storage, or where storage does not exist on a platform, samples of hydrocarbons exported from a platform should be taken;
ii) group produced water discharge; and,
iii) secondary streams, e.g. gas used for fuel, for gas lift and gas flared.

The Board may require increased sampling frequency respecting any of the above streams should evaluation requirements or environmental monitoring justify increased sampling.

(c) Sampling of Produced Water from a Well

Where water is produced from a well, either upon initial production, or during the producing life of the well, the operator will be expected to collect representative water samples to determine its probable source.

For this purpose, equipment should be capable of allowing detection of produced water during formation flow testing or during routine allocation tests, directly as a result of the separation process in place, or indirectly through real time monitoring of the outlet stream. Where produced water is detected or suspect, the operator should sample the fluid stream and obtain a representative samples of water for analysis.

The following measures should be taken by the operator where appropriate to determine the source of produced water:

i) obtain representative samples of formation water from all wells which encounter water-bearing reservoir within the approved development area;
ii) obtain representative samples of water injected into a pool;
iii) conduct tracer programs to identify the offending source of produced water; and,
iv) conduct cased hole logging, where practicable, to identify the offending zone or interval contributing to water production.

The operator is encouraged to acquire data early in the life of a pool or field to provide an effective means to assist in the determination of the source of any produced water.

Where water is produced from a well, the operator will be expected to monitor for increases in water production and where necessary take remedial action to control the influx of water for the purpose of maximizing hydrocarbon recovery.

9.2 Operational Guidance

Fluid sampling should be conducted in accordance with:

- **API RP 44 "Recommended Practice for Sampling Petroleum Reservoir Fluids", 2nd Ed, 2003;**
- **API RP 45 "Recommended Practice for Analysis of Oilfield Waters", 3rd Ed, 1998, reaffirmed by API January 2012.**

Note: *The Board does not require the operator to collect samples on its behalf in development wells. Exceptions would include formation flow tests conducted over secondary horizons not approved for development, i.e. refer to Section 7.2(c) of this guideline document.*

9.3 Deposition and Analysis of Fluid Samples

Section's 53, 54 and 55 of the regulations detail the requirements for the deposition and analysis of fluid samples from a well.

(a) Deposition of Samples from Site

All pressurized samples are to be transported in the appropriate Department of Transportation (DOT) approved containers. Atmospheric samples may be transported in suitable containers that prevents loss or deterioration of the sample.

Collection of fluid samples for the Board from development wells is limited to those samples collected from "secondary" horizons not as yet approved for development. Fluid samples should be delivered to the Board, within 60 days of being acquired, in accordance with Appendix B1**.** All sample containers must be suitably labelled or identified with the well name and source, and noting clearly the nature of the sample, i.e. oil, gas, gas condensate, water, or combination thereof.

(b) Fluid Analysis

Analyses of petroleum samples should be carried out in accordance with **API RP 44 "Recommended Practice for Sampling Petroleum Reservoir Fluids", 2nd Ed, 2003.**

The following types of analyses are expected to be conducted on samples obtained from wells completed in an oil pool:

- pressure-volume-temperature analysis;
- oil analysis;
- hydrocarbon liquid compositional analysis; and,
- gas compositional analysis;

while the following types of analysis are expected to be conducted on samples obtained from wells completed in a gas cap, or gas pool:

- pressure-volume-temperature analysis;
- gas compositional analysis;
- condensate compositional analysis; and,
- gas and condensate combined analysis.

Other types of analyses that may be carried out include:

- separator flash analysis;
- saturation pressure determination;
- true boiling point distillation; and,
- wax analysis.

The operator is referred to Appendix C8 when addressing the analysis of oil and gas samples. Appendix C8 summarizes the compositional and physical property requirements for analysis based on Section 11.07 of the Oil and Gas Regulations of Alberta.

Analyses of water samples should be carried out in accordance with **API RP 45 "Recommended Practice for Analysis of Oilfield Waters", 3rd Ed, 1998, reaffirmed by API January 2012.**

The results of any analysis conducted on fluid samples taken from development wells should be submitted to the attention of the Chief Conservation Officer.

9.4 Reporting Requirements

All fluid sampling information and analyses results must be submitted to the Chief Conservation Officer, within 60 days of acquiring the fluid sample. The operator is responsible for keeping the Board informed in writing respecting any delays related to the reporting of results.
A listing summarizing all fluid samples taken for analysis purposes during a calendar year should be provided in the Annual Production Report submitted for the field. This list should indicate the status of submissions made to the Board respecting any fluid analysis undertaken.

Submission requirements in respect of fluid analyses undertaken are defined in Section 2.1(4) of this guideline.

Additionally, the operator is requested to submit such reports where applicable in digital format as an Excel file, or a space delimited ASCII file, on USB, SFTP or other medium as approved by the C-NLOPB.

Disclosure of Information

Information or documentation, which includes samples, data, records and reports submitted to the Board in compliance with this document may be disclosed to any interested third party in accordance with the Acts.

For disclosure purposes, information submitted under these guidelines falls into three distinct categories:

(1) Information obtained as a direct result of drilling a well. This information will no longer be privileged and may be disclosed after the expiration of the periods indicated below:

- for an exploration well, two years after the well termination date;
- for a delineation well, the later of two years after the well termination date of the relevant exploration well, and 90 days after the well termination date of the delineation well; and,
- for a development well, the later of two years after the well termination date of the relevant exploration well, and 60 days after the well termination date of the development well.

Note: *Privileged periods for "information obtained as a result of drilling a well" may extend beyond those periods noted above for delineation or development wells where the operator of a delineation or development well targets a previously undrilled horizon. In such cases, the data release dates on well data within a well may vary. Please refer to the Board's "Schedule of Wells" for data release dates assigned to the well.*

Well termination date is defined within the Accord Acts as, "..the date on which a well or test hole has been abandoned, completed or suspended in accordance with any applicable regulation...".

- for exploration and delineation wells, the well termination date is the date on which the well is either suspended or abandoned.
- for development wells, the well termination date is the date on which the operator initially completes the well in accordance with the well completion program filed with the Board. This date typically coincides with the formal hand over of the well to production.

(2) Information obtained as a result of geological or geophysical work resulting from a well program. This information will no longer be privileged and may be disclosed after the expiration of five years from the date of completion of the work.

(3) Includes all remaining privileged information that does not fall into either of the above categories. This would include any information obtained as a result of an operation conducted on a well after the well termination date. This category is directly applicable to development wells and the body of information derived after the well termination date, which is the date the well is completed. Such

information shall not knowingly be disclosed, except for those purposes indicated under the Acts, without the written consent of the operator.

A listing of typical information submitted in support of well, pool and field programs and divided into the above categories has been provided in Appendix C9.

Appendix A – Operational “Waiver / Deviation” from an Approved Well Data Acquisition Program

C-NLOPB OFFSHORE PETROLEUM BOARD

C-NLOPB Operational "Waiver/Deviation" from an Approved Well Data Acquisition Program

To: Canada-Newfoundland and Labrador Offshore Petroleum Board

Attention: Adam Smith (Petrophysics Analyst) Phone: 778-1430, Cell: 690-6177 email: asmith@cnlopb.ca
Mike Stoyles (Operations Geologist) Phone: 778-4257, Cell: 730-2482 email: mstoyles@cnlopb.ca

From: Operator Contact Person (ph #: , cell #: , and email address)
Well: Official Well Name
Subject: Specifics of Waiver/Deviation Requested

In the table below, please summarize program commitments, current program status and proposed alternative.

Hole Section (mm)	Deviation	Mud	Program Approved	Acquired to Date	Proposed Alternative

Discussion of Rationale:

In this space, the operator should provide the rationale as to why it is requesting a waiver or deviation from an Approved Well Data Acquisition Program. Acceptable rationale would include deteriorating borehole conditions, weather conditions, or response to changing reservoir conditions, etc. Alternatives proposed to the Approved Well Data Acquisition Program should be included above and discussed in this section. The Operator's Representative should be named in the space below with the date of the request. The completed form should be emailed as a "Word" file to both C-NLOPB contacts.

Operator's Representative: ______________________________ **Date**: ____________

Where approval is sought outside of normal office hours, the Board's Petrophysicist should be contacted. Verbal approval can be granted in most cases by either of the above C-NLOPB contacts with supporting documentation (i.e. this form) to follow during normal business hours. The space below is reserved for a written ruling, signed and dated by a Conservation Officer. A "PDF" image file of this form will be emailed to the "Operator Contact Person" listed above.

C-NLOPB Ruling:

____

____

C-NLOPB Conservation Officer: ______________________________ **Date:** ____________

Appendix B1 – Relevant Addresses for the Submission of Materials and Information

All records and reports required by the Board should be submitted to:

Canada-Newfoundland and Labrador Offshore Petroleum Board (C-NLOPB)
Information Resources Centre
Suite 101, TD Place
140 Water Street
St. John's, NL
A1C 6H6

Contact: Information Resources Manager
Phone: (709) 778-1474
Email: information@cnlopb.ca

Any physical samples required by the Board should be delivered to:

Canada-Newfoundland and Labrador Offshore Petroleum Board (C-NLOPB)
Core Storage & Research Centre (CSRC)
30-32 Duffy Place
St. John's, NL
A1B 4M5

Contact: Dave Mills – Geological Services Supervisor
Phone: (709) 778-1500
Fax: (709) 778-1473
Email dmills@cnlopb.ca

Any physical samples for the Geological Survey of Canada (GSC) should be submitted to:

Geological Survey of Canada (GSC - Calgary)
Department of Energy Mines and Resources
3303 - 33rd Street NW
Calgary, AB
T2L 2A7

Contact: Richard Fontaine – Curator
Phone: (403) 292-7067

Appendix B2 – Reference Standards and Practices

- API RP 13B-1, “Recommended Practice for Field Testing Water-based Drilling Fluid”, 3rd ed., 2005.
- API RP 13B-2, “Recommended Practice for Field Testing Oil-based Drilling Fluid”, 5th ed., 2014.
- API RP 31A, “Standard Form for Hardcopy Presentation of Downhole Well Log Data", 1st ed., August 1997, reaffirmed by API January 2012.
- API RP 40, “Recommended Practices for Core Analysis”, 2nd ed., February 1998.
- API RP 44, "Sampling Petroleum Reservoir Fluids”, 2nd ed., April 2003.
- API RP 45, "Recommended Practice for Analysis of Oil-Field Waters", 3rd ed., , August 1998, reaffirmed by API January 2012.
- API RP 66, "Recommended Digital Log Interchange Standard (DLIS), Version 2.00", June 1996.
- ERCB Directive 034 “Theory and Practice of the Testing of Gas Wells”, 4th ed. (SI Units) 1979.
- ERCB Directive 040, "Pressure and Deliverability Testing Oil and Gas Wells”, December 2006.

Appendix C1 – Mud Log Example

The following criteria are suggested for the “Mud Log” referenced in Section 3.1 of this guideline document.

(1) The log should consist of the following tracks:

- Track 1- Rate of Penetration
- Track 2- Depth
- Track 3- Cuttings - Oil Show
- Track 4- Drilling Mud - Total Gas Units
- Track 5- Drilling Mud - Chromatographic Analysis
- Track 6- Lithology (Graphic)
- Track 7- Lithology Description & Remarks

(2) The scale of the log should be 1:600

(3) The log may be segmented to reflect the hole section being drilled.

The operator should indicate clearly on this log, the probable source of any gas that exceeds background levels. Equipment must be capable of continuous monitoring of drilling mud returns and provide for automatic detection and alarm in the event of any increase in gas levels. Equipment must be capable of measuring and recording total hydrocarbon gas content and recording the relative amounts of any methane, ethane, propane, and butane gas.

Appendix C2 – Downhole Logging & Survey Records Electronic Data Reporting Requirements

Format: The Board requires that the operator submit searchable PDF (electronic) copies of all logs and surveys in accordance with the format defined under **API RP 31A, "Standard Form for Hardcopy Presentation of Downhole Well Log Data", 1st ed., August 1997 (reaffirmed by API January 2012).**

The operator is asked to take note of the following particulars when complying with API RP 31A in the preparation and submission of electronic copies to the Board.

- Where applicable, each log should consist of two (2) depth scale presentations: the 'standard correlation log presentation' at 1:600 scale; and, the 'standard detail log presentation' at 1:240 scale.
- The calibration record provided with each log should, where practicable, include the results of calibration checks of the logging tool both before and after the logging run.
- Electronic copies generated must contain the repeat section(s) run prior to conducting the main pass.

Any "true vertical depth" logs generated should be distinct and separate from 'measured depth' logs. In this regard, all logs representing true vertical depth data should be clearly marked with the designation 'TVD' on the log header.

Copies: "Field" and "Final" copies: One searchable PDF copy of each for Exploration, Delineation and Development wells.

Where a log(s) requires no further processing, the operator may designate such a log(s) as "final". Otherwise, where subsequent processing is required, the operator should submit those electronic copies of "field" logs with copies of "final" logs to follow. All logs must be clearly marked on the log header as to whether they are "field" or "final" logs. Where logs are not clearly marked as "field" or "final", such logs will be treated as "field" logs by the Board.

Delivery: The operator should submit to the Board the required electronic copies of logs as soon as possible following the conclusion of logging operations for a given hole section. All logs submitted to the Board must have an accompaning transmittal slip.

Special: In circumstances where a quick response by the Board is warranted; i.e. where well evaluation is concerned, or when Board approval to suspend or abandon a well is required; the operator may be required to provide logs, in advance by USB, SFTP or other medium approved by the C-NLOPB.

Note: Although not required for submission, the Board reserves the right to request print copies of both field and final logs and surveys from the Operator. Where the Board requests submission of print copies of logs and surveys, the Operator should submit print copies of all logs and surveys in accordance with the format defined under API RP 31A, "Standard Form of Hardcopy Presentation of Downhole Well Log Data", 1st ed., August 1997 (reaffirmed by API January 2012).

Appendix C3 – Downhole Logging & Survey Records Digital Data Reporting Requirements

Format: The following represents the order of preference as to the format and medium in which digital data respecting logs and/or surveys may be submitted. When submitting geophysical data (i.e. check shot, velocity surveys etc.), the Board requests that this data be submitted in accordance with approach (b) below:

(a) As a complete data set, submitted in accordance with **API RP 66 - "Recommended Digital Log Interchange Standard (DLIS), Version 2.00"**. Data should be submitted on USB, SFTP or other medium approved by the C-NLOPB.

(b) As a subset of the complete data set, representing the optical curves presented on "final" logs. This data should be submitted preferably in accordance with the Canadian Well Logging Society's LAS 3.0 or alternatively LAS 2.0 format on USB, SFTP or other medium approved by the C-NLOPB.

(c) MDT header summary data and deviation surveys should be submitted in ASCII format on USB, SFTP or other medium approved by the C-NLOPB.

(d) Such other means as may be agreed upon or requested by the Board.

Note: *Digital log data is to be submitted in "measured depth" form as logged and must be in agreement with "final" logs submitted to the Board. See depth-shifting requirements of Section 6.2(b)(vi) for LWD and TLC based logs.*

Copies: One digital copy of data should be submitted to the Board in the format prescribed above andon USB, SFTP or other medium approved by the C-NLOPB. The operator is responsible for ensuring that all digital data is validated for accuracy and completeness prior to the submission of this data to the Board.

Delivery: Unless otherwise agreed upon, the operator is responsible for delivery of digital data to the Board at the earliest possible time and by appropriate means following completion of logging runs for a specific hole section.

Special: Where a quick response by the Board is warranted, the operator may be required to provide digital data by e-mail, sftp site or by other agreed upon means.

Appendix C4 – Formation Flow Testing Guidelines - Period Based Objectives "Exploration and Delineation Wells"

	Period	Status	Period Duration	Objectives
i)	Initial Flow	Mandatory	5 - 10 mins	Relieve supercharging within invaded zone.
	Initial Shut-in	Mandatory	90 mins	Determine initial reservoir pressure.
ii	Cleanup Flow	Mandatory	As Required	Establish flow of in situ fluids at surface.
iii)	Primary Flow	Mandatory	4 - 24 hours	Produce in situ fluids at stabilized rates. Acquire representative fluid samples.
	Primary Shut-in	Mandatory	8 - 48 hours	Acquire buildup data to identify flow behaviour and determine reservoir characteristics.
iv)	Sampling Flow	Optional	As Required	Acquire sub-surface fluid samples.
v)	Secondary Flow	Optional	Up to 4 days	Address additional operator objectives.
	Secondary Shut-in	Optional	As Required	Address additional operator objectives.

Note: *Please refer to Appendix C5 for regulatory expectations specific to drawdown and rate considerations associated with the “Primary Flow” period of formation flow testing associated with exploration and delineation well.*

Note: *The duration for the “Secondary Flow” period should not exceed 4 days noted above unless otherwise approved by the Chief Conservation Officer and Chief Safety Officer. This limitation is intended to minimize prolonged environmental or safety risks with respect to prolongued flaring operations. It is 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 defined under Section 140.2 of the Canada-Newfoundland Atlantic Accord Inplementation Act.*

Appendix C5 – Flow Testing Guidelines - Primary Flow Period "Exploration and Delineation Wells"

The operator is referred to the following operational guidelines when conducting the primary flow period of a formation flow test in an exploration and/or delineation well. This guidance is intended to simplify the primary flow period and thus minimize the complexity and uncertainty often associated with the analysis of pressure data for flow behaviour and in situ flow properties. The guidance provided is limited to considerations related to achieving drawdown consistent with a stabilized rate of flow.

Drawdown Considerations:

In establishing the desired drawdown, the operator should:

(a) minimize pressure shocks and unnecessary pressure transients through gradual adjustment of the surface choke to acquire sandface drawdown;

(b) ensure that sandface drawdown is sufficient to provide adequate resolution of pressure-time response by downhole gauges;

(c) for undersaturated oil reservoirs, attempt where practical to limit drawdown such that flowing sandface pressure is maintained above bubble point pressure;

(d) avoid inducing drawdown in excess of that induced during the cleanup period;

(e) ensure that wellhead pressure and separator pressure can be maintained at critical flow conditions;

(f) maintain choke at fixed bean setting once desired flow rate is obtained.

Rate Considerations:

In establishing the desired rate of flow, the operator should:

(a) avoid gas and/or liquid carry-over by restricting the rate of oil flow in accordance with the retention time appropriate to the capacity of separator equipment;

(b) ensure accurate rate measurement by comparing metered rates off the separator against tank volume measurements, and correcting metered rates using a meter adjustment factor;

(c) maintain a stabilized rate for a minimum of 4 hours before shut-in, or before a change in choke.

Appendix C6 – Pressure Gauge Comparison

	Mechanical[1] Gauge	Metal Strain[2] Gauge	Capacitance[1] Gauge	Sapphire[2] Gauge	Standard[2] Quartz Gauge	Compensated[2] Quartz Gauge
Advantages	Reliable Simple Rugged	Improved resolution Fast pressure response Rugged and small	Greater stability Lower power requirement	Improved stability Improved accuracy Fast pressure and temperature response Good resolution Very rugged	Best resolution Best stability Best accuracy	Best resolution Best stability Best accuracy Best dynamics Higher pressure range
Disadvantages	Poor resolution Poor stability Poor accuracy Tedious to read	Moderate stability Moderate accuracy Moderate temperature response time	Poor dynamic response Slower sampling Temperature and vibration sensitivity	Moderate temperature sensitivity	Poor dynamic response High temperature sensitivity Limited pressure rangeCost	More electronics Cost
Maximum Range	20,000 psi 200°C.	20,000 psi 175°C.	20,000 psi 175°C.	20,000 psi 175°C.	11,000 psi 175°C.	15,000 psi 175°C.
Resolution						
(full scale & sampling time)	(analog chart)					
20,000 psi and 1 sec	-5 psi	0.50 psi	0.20 psi	0.20 psi	N.A.	N.A.
15,000 psi and 1 sec	-2 psi	0.20 psi	0.15 psi	0.10 psi	N.A.	0.003 psi
10,000 psi and 10 sec	-2 psi	0.10 psi	0.05 psi	0.05 psi	0.007 psi	0.001 psi
Accuracy						
20,000 psi	-20 psi	18 psi	N.A.	6 psi	N.A.	N.A.
15,000 psi	-15 psi	12 psi	-12 psi	5 psi	N.A.	± (0.01% of reading + 2.0 psi)
10,000 psi	-10 psi	10 psi	-10 psi	4 psi	± (0.25% of reading + 0.05 psi)	± (0.01% of reading + 20 psi)
Drift						
10,000 psi and 150°C.						
1st day	-5 psi	<2-10 psi	<3 psi	<3 psi	<2 psi	<0.2 psi
1st 4 days	-10 psi	<3-12 psi	<5 psi	<5 psi	± 0.2 psi in 18 days	± 0.2 psi in 7 days
Long term	-5 psi/week	<2-4 psi/week	± 1-7 psi/week	<1 psi/week	<0.1 psi/week	<0.1 psi/week
Stabilization time						
After a 5,000 psi step	10 min est.	30 sec	8 min	20 sec est.	6 min	Always within 1 psi
After a 10°C step	10 min est.	10 min	40 min	10 min	25 min	Stable within 25 sec
Relative cost	Low	Low	Medium-high	Low-medium	High	High

Note: Table Provided for Reference Purposes Only – Units for Reporting Pressure – SI Units Only)
* Three key elements for successful testing, after Ehlig-Economides et al., *Oil and Gas Journal*, July 25th, 1994.

---

1 These are estimated figures based on published literature and manufacturers' commercial data.

2 These figures are based on Schlumberger's laboratory and field test data.

Appendix C7 – Pool Pressure Surveys - Procedure for Correcting Pressures to Datum Depth

Where required, the following equation should be employed by the operator when correcting run depth pressures to datum depth:

$$\mathbf{P_d = P_r + Gr_f\,(D_d - D_r)}$$

where:

P_d	- gauge pressure at datum depth, kPag
P_r	- gauge pressure at run depth, kPag
Gr_f	- wellbore fluid gradient, kPa/m
D_d	- datum depth, metres
D_r	- run depth, metres

Use of the above equation is required where:

(a) the distance separating run depth and datum depth is relatively small;

(b) oil is present in the wellbore to a depth up to, or shallower than, run depth; or

(c) the gradient of the wellbore 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.

Where the fluid gradient in the wellbore is different from the reservoir fluid gradient, the following two-step extrapolation procedure is required:

1) using the wellbore 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

2) using the reservoir gradient, extrapolate the pressure calculated above to the datum depth, having regard for any interfaces known to exist behind casing.

Appendix C8 – Fluid Analyses Requirements

The following requirements for fluid analyses are based on **Section T11.070T of the Oil and Gas Conservation Regulations of Alberta - AR151/71.**

Oil:

- density in kilograms per cubic metre at 15°C of the water-free and sediment-free oil;
- sulphur content of the water-free and sediment-free oil, weight percent;
- Saybolt Universal Viscosity in mPa.sec of water-free, sediment-free oil at 20°C, and 40°C;
- mole fraction, mass fraction and liquid volume fraction of nitrogen, carbon dioxide, hydrogen sulphide,
- methane, ethane, propane, iso-butane, normal butane, iso-pentane, normal pentane, and hexanes plus.

Gas:

- density in kilograms per cubic metre @ Std. conditions;
- gross heating value for moisture and acid gas free gas @ Std. conditions;
- pseudocritical pressure and temperature, calculated as sampled in kPa and °K;
- gas composition in:
    - moles per mole of methane, ethane, propane iso-butane, normal butane iso-pentane, normal pentane, hexanes, heptanes plus, nitrogen, helium, carbon dioxide and hydrogen sulphide; and,
    - moles per mole converted to litres per thousand cubic metres of propane, iso-butane, normal butane, iso-pentane, normal pentane, hexanes and heptanes plus.

Condensate:

- density in kilograms per cubic metre @ Std. conditions of the water-free and sediment-free condensate;
- mole fraction and liquid composition in moles per mole of nitrogen, carbon dioxide, hydrogen sulphide, methane, ethane, propane, iso-butane, normal butane, iso-pentane, normal pentane, hexanes and heptanes plus;
- molecular weight in grams per mole of the heptanes plus fraction.

Gas and Condensate Combined:

- density in kilograms per cubic metre, measured or calculated from the recombined analysis;
- pseudo-critical pressure and temperature calculated from the recombined analysis;
- liquid to gas ratio expressed in cubic metres per cubic metre;
- mole fraction and gas composition in moles per mole of nitrogen, helium, carbon dioxide, hydrogen sulphide, methane, ethane, propane, iso-butane, normal butane, iso-pentane, normal pentane, hexanes and heptanes plus;
- molecular weight and density in kilograms per cubic metre of liquid hydrocarbons;
- molecular weight in grams per mole of the heptanes plus fraction.

Water:

- solids contents in kilograms per cubic metre, and the calculated percent solids of chloride, bromide, iodide, carbonate, bicarbonate, hydroxide, sulphate, calcium, magnesium, sodium and total solids;
- total solid content by evaporation at 110°C, 180°C and at ignition;
- density in kilograms per cubic metre @ Std. conditions;
- pH and resistivity in ohm-metres @ 25°C;
- hydrogen sulphide in grams per cubic metre;
- refraction index at 25°C.

Note: *The above measurements are presented as a guide. The Board recognizes that certain labratories may have modified/evolved analyses practices, and may no longer conduct analyses to the extent indicated above. Operators are requested to note in the submission of analysis results where specific analyses were not undertaken.*

Appendix C9 – Classification of Information

The following information is typical of the data that may derive from well evaluation programs. The data listing below is not intended to be exhaustive.

(1) The following data result directly from the drilling of a well. This data will no longer be privileged and may be disclosed after the period of confidentially for the well has elapsed:

- drill cuttings;
- conventional and sidewall cores;
- well fluid samples;
- drilling mud report form(s);
- deviation and drift surveys;
- gas detector log or mud logging records;
- age determinations (K/Ar, etc.);
- photographic record of cores under natural and ultra-violet light;
- engineering data resulting from analysis of cores and cuttings, including routine and special core analyses;
- open-hole logs and any cased-hole logs run prior to the well termination date;
- details and results of formation flow tests;
- oil, gas and water analysis from formation flow tests;
- details and results of production or injectivity testing conducted on zones or pools in a field in accordance with the well's initial completion program;
- any oil, gas and water analysis resulting from the well's initial completion program;
- Well History Report.

(2) The following data result from geological or geophysical work. This data will no longer be privileged and may be disclosed after the expiration of five years following the date of completion of the work:

- synthetic seismograms;
- velocity surveys;
- vertical seismic surveys;
- petrological reports;
- paleontological reports;
- palynological reports;
- geochemical reports;
- logs requiring secondary processing.

(3) The following data represents information from development wells obtained as a result of operations conducted after the well termination date. This data shall not knowingly be disclosed, except for those purposes indicated under the Acts, without written consent of the operator;

- cased-hole logs;

- details and results of any formation flow testing respecting production or injectivity testing conducted on zones or pools in a field;
- details and results of formation flow tests respecting the evaluation of secondary horizons in a field;
- any oil, gas and water analysis resulting from well, pool and field monitoring;
- the annual pool pressure surveys for a field;
- the annual fluid compositional analyses for a pool in a field.

Appendix D – Well History Report - Reporting Requirements Related to Evaluation Programs

A “Well History Report” is a requirement of Section 89 of the Regulations. The reporting requirements specific to well evaluations have been defined in guidance provided in this document, and have been consolidated in this appendix in support of the well history report. Where secondary reports are generated, either by the operator or by third parties resulting from analysis of well data and relevant to the information required by the well history report, such reports should be submitted to the Board with an accompanying cover letter.

Copy requirements respecting the “Well History Report” or any associated secondary report follows:

- One electronic copy as a searchable PDF file submitted on USB, SFTP or other medium approved by the C-NLOPB , of the Well History Report or any secondary report(s) relevant to evaluation programs conducted in support of a well data acquisition program.

- One copy of digital data related to cores, logs, surveys and analyses conducted, submitted in the format and on the media as prescribed within these guidelines in support of a well data acquisition program.

In submitting information pertinent to well evaluation programs, the operator is requested to adhere to the following format:

Geology (Exploration, Delineation and Development Wells)

i) 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.

ii) Cores

For conventional core: a table showing the core number, interval, and amount of recovery. The storage location of conventional core should be indicated.

For sidewall core: a table showing for each coring run, the depths sampled and results achieved (e.g. recovery, misfires). Where applicable, the type of analyses preformed on each sample, and whether or not the sample was tested to destruction should be stated. The storage location for any remaining sidewall core should be indicated.

Any separate core analysis reports (routine and special), including any reports of core photographs related to samples collected, should be provided upon completion.

iii) 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.

iv) 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.

v) 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 his effect should be included.

Well Evaluation (Exploration, Delineation and Development Wells)

i) Deviation & Drift 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 degrees from the vertical over any part of the hole. Bottom-hole coordinates referenced to surface location should be provided for all wells.

ii) Mud Log & Drilling Fluid Report Form

The following should be included:

- the records from gas detection and mud logging, i.e. Appendix C1.
- the records respecting the drilling fluid system for each phase of the hole, i.d. Drilling Mud Report Form, Section 3.0 of this guideline.

iii) Downhole Logs & Surveys

A list/table should be provided showing all logs and/or surveys run in the well noting the date, run number, type, interval, and service company. Electronic copies of “final” logs not submitted previously should be submitted at this time.

Where geophysical surveys are conducted, the following information is to be included in the final well report:

- the final report of velocity surveys (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 operators most recent seismic data in the vicinity of the well.

- the final report(s) associated with VSP surveys, including;
  - displays of the downgoing and upgoing waves, prior to and post processing, displayed at the same scale as the operator's seismic data in the vicinity of the well;
  - a description of the processing sequence applied to the data; and,
  - any composite logs produced.

iv) Completion Records and Formation Stimulation (if applicable)

The following should be included:

- a copy of the completion record for development wells noting the interval perforated and by way of schematic, the equipment installed on the well where it directly affects well production or well evaluation; and,

- a copy of any report respecting well stimulation including the date of stimulation, intervals, method, contractor, stimulants, and quantities and results.

v) Formation Flow Test Results

A brief summary of the results and reports associated with each formation flow test conducted for exploration or delineation wells. The date, test number, and interval tested should be provided. 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 final well report, copies of:

- reports submitted to the operator by service companies and consultants relevant to the conduct of the test conducted; and,
- fluid analysis reports of oil or condensate, gas and water samples collected either from a wireline survey, or as a result of a formation flow test or initial production/injection test conducted.

Results of formation flow tests conducted on development wells covered the “Standard Test Program” detailed under Section 7.1.2 of this guideline should be documented as part of the “Annual Production Report” submitted for the field.

Appendices to the Well History Report

Appendices may be used to give details on the subjects below, if such have not been given elsewhere in the report.

i) Petrological reports.*
ii) Paleontological reports.*
iii) Palynological reports.*
iv) Geochemical reports.*
v) Age determinations (K/Ar, etc.).
vi) Reservoir engineering data on cores and cuttings, including the data and results of all routine and special core analysis studies.
vii) Photographic record of core under natural and ultra-violet light.
viii) Mud Loggers Report.
ix) Drilling Fluid Report Form.
x) Deviation and drift records.
xi) Logs requiring secondary processing.
xii) Details of formation flow testing for exploration/delineation wells
xiii) Oil, gas and water analyses.
xiv) Completion data such as tubing and stimulation records.
xv) Composite well records.
xvi) Final survey plan.

* Pursuant to the Act this information will be kept confidential for five years.