CANADA-NEWFOUNDLAND OFFSHORE PETROLEUM BOARD

Canada - Nova Scotia Offshore Petroleum Board

Canada-Newfoundland Offshore Petroleum Board / Canada-Nova Scotia Offshore Petroleum Board

Joint Guidelines
Respecting Data Acquisition and Reporting
for
Well, Pool and Field Evaluations
in the
Newfoundland and Nova Scotia
Offshore Areas

June 2003

Note

To ensure flexibility and clarity within the regulatory regime, these Guidelines create a framework for activities in the Newfoundland and Labrador offshore area and the Nova Scotia offshore area. The Guidelines provide specific direction where the Board has been given authority to prescribe and guidance where the Board may approve certain activities. Further, direction is also given on how the Board interprets the broadly based legislative requirements governing the offshore area. To ensure responsiveness, these Guidelines may be reviewed from time to time, and where necessary updated. As part of any planning process for activity in the offshore area, contact should be made with the appropriate departments of the Board to confirm the status of any particular Guideline and any legislative requirement.

Italicized text has been used to highlight the differences in regulatory requirements between the Canada - Newfoundland Offshore Petroleum Board (C-NOPB) and the Canada - Nova Scotia Offshore Petroleum Board (C-NSOPB).

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Introduction

The Canada-Newfoundland Offshore Petroleum Board ("C-NOPB") and the Canada-Nova Scotia Offshore Petroleum Board ("C-NSOPB") are the authorities responsible for the administration of the regulations pertaining to the exploration for and production of hydrocarbons in the Newfoundland and Nova Scotia offshore areas respectively.

In this document the following definition is used:
Board refers to the Canada-Newfoundland Offshore Petroleum Board (C-NOPB) in respect of drilling and production operations in the Newfoundland offshore area and the Canada-Nova Scotia Offshore Petroleum Board (C-NSOPB) in respect of drilling and production operations in the Nova Scotia offshore area.

This guideline document has 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. The document is divided into two parts reflecting the requirements of:

The Drilling Regulations:

(i) *the Newfoundland Offshore Petroleum Drilling Regulations (SOR/93-23 28 January, 1993),*

(ii) *the Nova Scotia Offshore Petroleum Drilling Regulations (SOR/92-676 23 November, 1992).*

The Production and Conservation Regulations:

(i) *the Newfoundland Offshore Area Petroleum Production and Conservation Regulations (SOR/95-103 21 February, 1995),*

(ii) *the Nova Scotia Offshore Area Petroleum Production and Conservation Regulations (SOR/95-190 11 April, 1995).*

Additional copies of this document may be obtained from either the C-NOPB or the C-NSOPB at;

Canada-Newfoundland Offshore Petroleum Board,
Suite 500 TD Place, 140 Water Street
St. John's, NF., A1C 6H6
Tel/Fax: (709) 778-1400/1473
URL: http://www.cnopb.nfnet.com

Canada-Nova Scotia Offshore Petroleum Board
6th Floor TD Centre, 1791 Barrington Street
Halifax, N. S., B3J 3K9
Tel/Fax: (902) 422-5588/1799
URL: http://www.C-NSOPB.ns.ca

- 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 deg C.

Data in formats other that those prescribed in these guidelines may be acceptable. Persons wishing to submit data in another format must obtain the prior approval of the Board's Chief Conservation Officer (CCO).

Use of Language in the Guidelines

The Boards position respecting well evaluation programs falls under two catagories: those well programs that are mandatory would be referred to by the word 'required', and those that are optional or at the discretion of the operator would be referred to by the word 'encouraged'.

The phrase "unless otherwise approved" is included in the guidelines, for the operator's benefit, to allow an operator, where exceptional or special circumstances exist, to make a case for an exemption either up front as part of the ADW, or at anytime during the drilling of the well. Each case will be reviewed and a decision made by the CCO or the Board at that time.

Part 1 Evaluation Guidelines Specific to the Drilling Regulations

1-1 Introduction

The Newfoundland and Nova Scotia Offshore Petroleum Drilling Regulations, hereafter referred to in Part 1 of this document as the regulations, apply in respect of every well drilled in the Newfoundland and Nova Scotia offshore areas.

The requirements for well evaluation are primarily contained in Part VI of the regulations and apply to:

. drill cuttings;
. cores;
. mud gas monitoring;
. wireline logs; and,
. testing and sampling.

An operator is required to submit its proposed program for well evaluation as part of the application required by Section 68 of the regulations for an Approval to Drill a Well (ADW). The application is required 21 days prior to the anticipated spud date.

The submission should contain the details of the evaluation programs proposed, to the extent that such detail is possible prior to commencement of drilling. Issuance of an ADW will be dependent, in part, upon whether the programs proposed provide 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.

The operator of a field undergoing development will be expected to submit an evaluation strategy for a well, pool or field in advance of drilling and to carry out this strategy through specific ADW submissions. This program should simplify subsequent applications for ADW's. The operator is encouraged to design its program to provide sufficient flexibility to respond to changing needs as the field is developed. Any such program would be approved by the Board for a limited period of time.

1-2 Well Evaluation Programs

The guidance provided for well evaluation programs is intended to assist the operator in the following areas:

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

These are discussed below.

(1) Program Design

In preparing its ADW application, an operator is referred to the general requirements for evaluation set out in Section 160(1) of the regulations which states;

"Every operator shall obtain sufficient well tests, wireline logs, analyses, surveys and samples during the drilling of a well to ensure that a comprehensive geological and reservoir evaluation can be made."

The Board will seek to ensure that any program proposed provides for a comprehensive evaluation of the well, consistent with the class of well being drilled. Unless otherwise approved, the Board discourages for the benefit of well evaluation, the use of turbo drilling in those exploration wells located in rank wildcat areas. The operator is also referred to the "Offshore Waste Treatment Guidelines, August 2002" for the requirements specific to mud systems used in offshore areas. We emphasize that the requirements for OBM are different from SBM, which are different again from water based muds. Where operators of an exploration well wish to use a mud system other than water based, the reasons for doing so must be outlined in the ADW.

The Boards also recognize the additional challenges associated with exploration and development in the deep-water environment. While the regulations do not differentiale between wells drilled in "shallow" water and wells drilled in "deep" water, the Boards have attempted to balance the well evaluation requirements reflected in these guidelines against the challenges of the deep-water envirnonment.

In general terms, the Board criteria for assessing the acceptability of well evaluation programs is linked to the well's classification at the time the ADW application is submitted:

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 the level of evaluation outside of targeted production intervals that is necessary to meet regulatory requirements.

The specific requirements for well programs reflecting a class of well are presented under the subject headings that follow this introduction.

(2) Operational Guidance

Guidance is provided 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 and Analysis Requirements

Guidance reflects the requirements of Part VIII of the Drilling Regulations where cuttings, cores and fluid samples have been acquired as a result of well programs.

(4) Reporting Requirements

Section 4 of the regulations provides that any information that is required by the regulations be submitted in a form and manner satisfactory to the Board. Parts V and IX of the regulations define the requirements for operational records and reports, and for final well reports respectively.

• Operational Records and Reports

The operator is requested to submit one 'print' copy of those operational records and reports specified in Sections 153 through 156 of the regulations the requirements for which are further detailed within these guidelines.

• Final Well Report

A final well report is a requirement of Section 201 of the regulations. Information requirements pertinent to well evaluations have been detailed throughout the body of this document, and summarized in its entirety in Appendix D.

. *For exploration and delineation wells, the C-NOPB requires that an operator submit three (3) print copies of the Final Well Report unless otherwise specified in the ADW approval. The C-NSOPB requires that the operator submit four (4) print copies of the Final Well Report.* The Final Well Report must be submitted within 90 days of the rig release date.

. *For development wells, the C-NOPB requires that an operator submit three (3) print copies of the Final Well Report. The C-NSOPB requires that an operator submit four (4) print copies of the Final Well Report.* The Final Well Report must be submitted within 45 days of the well termination date*.

Secondary reports reflecting analyses or studies relevant to the information required by the final well report should be submitted upon completion of the work. Secondary reports should be submitted with an accompanying transmittal.

* See the "Disclosure of Information" section at the conclusion of Part 2 of this document for the definition of 'well termination date'.

1-2.1 Drill Cuttings

Sections 161 and 200 of the regulations require the operator to collect drill cuttings from a well in accordance with the program approved as part of the ADW, and to provide samples of those cuttings to the Board.

1-2.1.1 Program Design

An operator is referred to the following requirements for the sampling of drill cuttings when preparing its application for ADW.

• Exploration/Delineation Wells

Unless otherwise approved, sampling of cuttings will be required at 5 metre intervals, commencing at the base of surface casing and continuing to the total depth for the well. Consideration may be given to relaxing these requirements where doing so can be justified by the operator. Complete sets of the following three types of samples are required by the Board.

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

. *1 set packed in 25 ml transparent vials to be sent to either the C-NOPB's Core Storage & Research Centre (CSRC) located in St. John's, NF. (see Appendix A) for wells drilled in the Newfoundland Offshore area or to the C-NSOPB's Core and Data Archive Facility in Dartmouth, N.S. (see Appendix A) for wells drilled in the Nova Scotia Offshore Area.*

and,

. 1 set packed in 15 ml transparent vials for the C-NOPB or C-NSOPB, c/o the Geological Survey of Canada (GSC), Calgary, AB. (see Appendix A).

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. *Samples should be shipped to either the C-NOPB's CSRC in St. John's, NFLD or the C-NSOPB's Core and Data Archive Facility in Dartmouth, N.S. as appropriate (see Appendix A).*

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.

C-NOPB: *The C-NOPB does not presently require "pre-washing" of unwashed cuttings prior to submission to the Board. 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.*

C-NSOPB: *Where the well has been drilled with oil based or synthetic mud, operators will be required to "pre-wash" all unwashed drill cuttings prior to submission. This "pre-wash" should remove the majority of the drilling fluid while minimizing any damage to the samples. These samples should be dried at temperatures which will not adversely affect their geoscientific value.*

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. Rims should be cleaned to ensure a proper seal. *Samples should be shipped to either the C-NOPB, c/o the Geological Survey of Canada (GSC), Calgary, AB. or to the C-NSOPB's Core and Data Archive Facility, as appropriate (see Appendix A).*

• Development Wells

Board 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 the field should discuss its proposal with the Board's staff prior to submission of the ADW application. Where relaxation is being considered on an ongoing basis, an amendment to the well evaluation program for the field should be submitted.

1-2.1.2 Deposition Requirements

In preparing samples for deposition from the drilling site, the operator is required to ensure:

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 labelled boxes or containers appropriate for shipment.

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

1-2.1.3 Reporting Requirements

(a) Operational Records and Reports

Section 153 of the regulations requires an operator to submit to the Board routine weekly reports on the lithology of the formation drilled, and the nature of formation fluids encountered. Where daily reports are prepared for internal company purposes, such reports may be provided in lieu of weekly reports. Submission of routine reports should be by 'secure' FAX, or by other agreed upon means.

(b) Final Well 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 print copy requirements for final well reports, the Board requires that where data exists in digital form, two copies, are to be provided in ASCII format, on CD.

1-2.2 Cores

Sections 162, 163 and 200 of the regulations require that an operator take cores in accordance with the program approved in the ADW and that samples of these cores be submitted to the Board.

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

C-NOPB: *The C-NOPB does not presently require "washing" of conventional core prior to submission to the Board. Where the mud system, gels used in coring, or lubricants used in the cutting of core plugs coat the core in a manner that "obstructs" the viewing of the core, the operator should ensure that the core face is cleaned prior to submission.*

C-NSOPB: *The C-NSOPB presently requires "washing" of conventional core over all hole sections drilled with OBM/SBM. In addition, the residue of any compounds used during the cleaning process (e.g. toluene) must be removed from the core prior to submission. The washing process must be conducted in a manner which minimizes the damage to the core. All samples necessary for analysis should be removed prior to washing the core."*

1-2.2.1 Program Design

An operator is referred to the following regulatory expectations respecting the taking of cores when preparing its application for an ADW.

(a) Conventional Cores

An operator is requested to set out in its ADW application the criteria (e.g. drilling breaks, shows, etc.) to be followed for the cutting of core.

- Exploration Wells

Unless otherwise approved, the Board requires that, where practicable, operators cut core from each hydrocarbon-bearing formation that is designated by the operator as a target for the well. The Board encourages the operator to core other hydrocarbon-bearing horizons where encountered and where the approved coring criteria is satisfied.

The operator is also encouraged to core reservoir quality rock in "rank" exploration areas.

- Delineation Wells

Unless otherwise approved**,** the Board requires that, where practicable, operators cut core representative of the entire reservoir interval. This could include coring the entire reservoir interval.

Additionally, the Board encourages operators to cut core from all other hydrocarbon-bearing formations encountered outside of the targeted intervals.

- Development Wells

The coring of development wells is subject to the requirements of the Production and Conservation

(P&C) Regulations and the guidance respecting those regulations provided in Section 2-2.1 of this document.

(b) Sidewall Cores

Guidance on sidewall coring for all well classifications is provided below. For all wells, the choice of technology employed (i.e. rotary or percussion) in obtaining sidewall cores should be appropriate to the analysis objectives.

- Exploration Wells

Unless otherwise approved, sidewall cores are required, where practicable, 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.

An operator of a well being drilled in a “rank” exploration area will be required to sidewall core, where practicable, all potential reservoir quality rock and potential source rock where conventional core was not obtained.

- Delineation Wells

Unless otherwise approved, sidewall cores will be required over reservoirs targeted for appraisal where conventional core was not obtained or as a supplement to conventional core where the reservoir is not adequately characterized.

- Development Wells

An operator of a development well may be required by the Board to obtain sidewall core, where practicable, in a well where conventional core was targeted but not obtained.

For any of the above well types, the Board or the CCO may request, either as a condition of approval of an ADW or in response to viewing logs, that sidewall cores be taken from designated wellbore interval(s). In the latter instance, the Board may request that logs required be faxed or electronically transmitted (i.e. via email or downloaded from a secure server, etc.) in accordance with the 'Special Circumstances' noted in Schedule 2a of these guidelines.

1-2.2.2 Operational Guidance

The operator should utilize good coring practice (i.e. sleeves) when acquiring conventional core. All core upon removal from a well should, where possible, be marked with chalk or a felt marker for the purpose of recording core orientation in the case of conventional core, or the depth of recovery for sidewall cores.

1-2.2.3 Deposition and Analysis of Samples

(a) Preparing Core for Shipment

- 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 __.

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.

• Sidewall Core

Each sidewall core should be placed either in a glass jar or, preferably, plastic vial. Rotary sidewall cores cut for routine analysis purposes should be preserved by wrapping and dipping the core in wax or filling the jar with base fluid. Each jar or vial must be clearly and indelibly labelled with the well name and the depth from which the sample was obtained. Samples should be securely packed for shipment, to the Board, 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 ___ ".

(b) Analysis and Delivery of Core to the Board

• Conventional Core

Conventional core must undergo the routine core analyses indicated in Section 198 of the regulations. To this end, an operator should ensure that:

i) where applicable (i.e. as dictated by the bedding plane) in addition to plug permeability measurements obtained, adequate samples of full diameter core are analysed to yield measurements of core permeabiliy in three directions;

ii) fluid saturation measurements include the residual saturation of oil and water fractions remaining in the core.

The Board requests that operators also provide where measurements have been taken, readings of the core's natural gamma activity, bulk density, calculated grain density, and as well provide a visual description of core for lithology and hydrocarbon shows.

Following sampling of the core for reservoir analyses, the remaining core or a longitudinal slab that is not less than one-half the cross-sectional area of the core is to be sent to either the C-NOPB's CSRC or the C-NSOPB's Core and Data Archive Facility, as appropriate. Delivery is routinely required within 60 days of the rig release date in accordance with Section 200 of the regulations. The Board recognizes however that delays beyond 60 days are possible given the lack of local facilities. To this end the Board expects operators to notify the Board respecting any delays and to employ due diligence in ensuring samples and analyses results are submitted as soon as possible.

• Sidewall Core

Sidewall core remaining after routine or special core analysis, petrographic, biostratigraphic or other analyses must be delivered to the Board (Appendix A) as per the requirements of Section 200 of the regulations.

The Board requests that operators prepare a list to accompany sidewall cores shipped to the Board identifying the cores included in the shipment and those 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 preformed, e.g. routine or special core analysis, petrographic, palynological or foraminiferal slide preparation, geochemical analysis.

1-2.2.4 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 routine reporting procedures for drill cuttings described in Section 1-2.1.3 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 requirements for 'downhole survey records' as described in Section 154 of the regulations and Section 1-2.4.3 of this document.

(b) Final Well Report

This 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 print copy requirements for final well reports, the Board requires that two digital copies of the above data are to be provided in ASCII format on CD.

1-2.3 Gas Content of Drilling Fluid

Section 164 of the regulations requires that an operator sample and test all drilling fluid returning to surface for gas content.

1-2.3.1 Program Design

Equipment employed in the monitoring of drilling fluid is considered to be part of the 'Drilling Fluid System' described in Section 60 of the regulations. This equipment must be capable of continuous monitoring of mud returns and provide for automatic detection and alarm in the event of any increase in gas levels. Equipment must measure and record total hydrocarbon gas content and record the amounts of any methane, ethane, propane, and butane gas.

For this purpose, operators are referred to the requirements of Section 98 of the regulations - 'Monitoring of Drilling'. Specifically, the operator should record any measurements taken with respect to Section 98(a) in the following manner.

i) Regarding Section 98(a)(i), an operator should report on drilling fluids in accordance with API RP 13G - 'Recommended Practice - Standard Procedure for Drilling Mud Report Form'.

ii) Regarding Section 98(a)(ii), an operator should establish and maintain at the rig site, a mud log for the well containing the information described in Schedule 1 of this document. The operator should indicate clearly on this log, the probable source of any gas that exceeds background levels.

1-2.3.2 Operational Guidance

Equipment employed in the monitoring of gas content of drilling fluid should be maintained and calibrated in accordance with manufacturers recommended practice. Operators are requested to retain the record of all maintenance and calibration checks preformed during the drilling of the well for 6 months following termination of drilling. This record should be made available to the Board upon request.

1-2.3.3 Reporting Requirements

(a) Operational Records and Reports

The operator is required to report mud gas readings as part of the routine lithology report required by Section 153 of the regulations. These readings should be submitted to the Board in accordance with the routine reporting procedures for drill cuttings described in Section 1-2.1.3 of this document.

(b) Final Well Report

The Board requests that the operator submit the Drilling Mud Report Form and the Mud Log prepared for the well as part of the final well report.

1-2.4 Logs and Surveys

A basic component of well evaluation includes logs and surveys run to obtain petrophysical, geological and geophysical data on the formations encountered.

1-2.4.1 Program Design

An operator is required to detail its proposed program for logging and surveying a well as part of the

documentation submitted in support of its application for an ADW.
Two types of logging programs are consistent with regulatory expectations. These are:

i) the petrophysical and geological evaluation conducted in open hole, and;

ii) the geophysical evaluation that is typically conducted in cased hole.

These programs will be subsequently referred to as the open hole and cased hole logging programs for a well. The cased hole program discussed in this section should not be confused with the cased hole requirements for the monitoring of development wells introduced in Part 2 of this document.

For the purpose of clarification, the regulatory use of the term 'wireline' is not intended to restrict the means of conveying logging tools in the well but rather would include all means of conveying such tools that result in an equivalent level of evaluation, e.g. logging while drilling (LWD), or the conveying of such tools by pipe or by coiled tubing means in deviated wells.

(a) Open Hole Logging Program

Operators are referred to the specific regulatory requirements applicable to the logging of open hole sections of a well contained in Sections 165 through 169 of the regulations.

Unless otherwise approved, the measurements referred to in Section 165 must be reflected in the logging program proposed for the well. The following clarification is provided with respect to the requirements of this section:

i) Measurements should be made employing technology that is compatible with the complexity and significance of the formation drilled.

In delineation and/or development wells, logging tools should be selected to provide the necessary resolution such that measurement accuracy and reservoir characterization over productive intervals is maximized. Use of borehole imaging and array based technologies is encouraged where thinly interbedded or naturally fractured reservoirs are encountered.

ii) While the inherent benefits associated with logging while drilling are recognized in Section 165(3), the limitations of this technology are also recognized, i.e. reduced and variable sampling frequency in comparison with wireline based logging. Therefore, unless otherwise approved, the Board will not accept logs derived while drilling in place of wireline logs in either exploration or delineation wells. Exceptions may be made for the logging of hole sections exhibiting little geological or reservoir significance.

Where equivalency has been established with the Board respecting specific wireline tools and equivalent logging while drilling based tools, the Board will accept the latter in lieu of wireline logging in development wells provided that both tools and logging are run in such a manner as to maximize the quality of data obtained.

iii) The use of such qualifiers as 'sufficient' and type' in reference to logs as employed in Sections 165 (4), (5) and (6) is intended to ensure that the evaluation is consistent with the complexity and significance of the formation being logged. Multiple types of logs may be required to ensure accurate determination of in situ matrix or fracture porosity and fluid saturation.

The types of logs referred to for porosity and resistivity measurements includes sonic, neutron and density type tools for measurement of in situ porosity, and induction and laterolog type tools for measurement of in situ resistivity. Resistivity tools should be capable of at least three depths of investigation in order to adequately characterize and compensate for mud filtrate invasion.

• Granting of Dispensation

The CCO may grant dispensation from measurement requirements where circumstances exist whereby logs would yield erroneous results or be of inconsequential value to well evaluation. Such instances may arise as a result of a lack of reservoir development, the mud system employed, simply as a result of wellbore conditions which make the acquisition of logs impractical. Dispensation granted to date includes:

i) relief from taking measurements of spontaneous potential, SP, in oil-based or synthetic based muds; and,

ii) relief from taking laterolog type resistivity measurements in oil-based or synthetic based muds.

In development wells, the operator may be permitted to conduct a reduced logging program over non-reservoir intervals outside of the targeted productive interval. The operator should support its case for a reduced logging program in hole sections or over intervals of limited interest through the data acquisition program submitted for the field.

Any operator seeking dispensation should approach the CCO in writing during the ADW application process, or during the progress of the well at such time its case for dispensation can be supported.

(b) Cased Hole Logging Program

A cased hole logging program for a well would typically consist of those logs run to evaluate the quality of casing cementation and, logs run to acquire geophysical measurements.

• Casing Cementation Evaluation

Unless otherwise approved, the operator is required in accordance with Sections 56-57, 94, 184 and 193 of the regulations, to carry out an independent assessment by logging of casing and/or liner cementation in all wells.

This assessment, which is necessary to address the issue of zonal isolation, should be capable of assessing the integrity of cement bonding to casing and to the formation and also be capable of detecting channels behind casing that might provide pathways for reservoir fluids. Where the question of zonal isolation is a serious concern, the CCO may, in these circumstances (i.e. where a proposed evaluation program may be compromised or if resource conservation issues arise), require the operator to take necessary remedial action, e.g. cement squeeze.

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.

• Well Geophysical Surveys

A check shot survey is required for all exploration and delineation wells. The Board, in consultation with the operator, may request the operator to acquire a vertical seismic profile (VSP), where it would contribute to resolving uncertainty associated with seismic interpretation.

It is likely that geophysical surveys will be needed in some development wells to acquire additional control for the seismic interpretation of the field. In such instances, the Board may request that an operator conduct such survey(s) should they be necessary.

(c) Program Submission to the Board

Proposed logging programs submitted as part of an ADW application should take the following format:

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 indicate 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 may consist of a single logging run with all logs combined and run in the hole simultaneously, or a number of logging runs with tools run in smaller combinations or run individually. For each 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.

iii) In exploration wells, primary open hole measurements indicated in Section 165 of the regulations should be obtained prior to conducting other surveys, e.g. wireline testing, sidewall coring, etc.

Where any tool or tool combination being proposed is designated as optional, the operator is requested 'to state clearly' the criteria which will determine whether this tool will be run.

(d) Program Approval

Approval of a logging program is given with the issuance of an ADW which is dependent in part upon the program satisfying the requirement that it provides for a comprehensive evaluation consistent with the class of well being drilled. Where a field is being developed, the operator is encouraged to submit the details of it's open and cased hole logging programs, for the field. Where such a program has been approved, the operator need only reference this program when filing an application for ADW.

In keeping with the intent of Section 160 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 ADW process, and would be included as a condition of granting an ADW.

Should an operator wish to deviate from an approved logging program during the drilling of a well, the operator must first seek the approval of the CCO stating the reasons for the proposed departure from its program. The CCO may approve such requests where dispensation is justified, or where alternatives are proposed that are equivalent or an improvement to the initial program.

1-2.4.2 Operational Guidance

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

(a) Drilling Fluid

Section 60 of the regulations requires that the operator give due consideration to evaluation requirements when selecting the drilling fluid for the well. Drilling fluids should be compatible with expectant lithology and the logging tools necessary for well evaluation.

Where the operator plans to alter its mud system, the operator may be required in accordance with Section 165(3) of the regulations, to log the hole section before altering the nature of the drilling fluid where altering fluid would affect the quality of data acquired.

A report indicating the constituent components of the mud system used during the drilling of each hole section, and at the commencement of logging open hole sections should be submitted to the Board in accordance with API RP 13G - 'Standard Procedure for Drilling Mud Report Form'. Refer to Section 1-2.3.1 of this guideline document.

(b) Logging Operations

Following is a list of requirements and recommendations applicable to logging operations:

i) 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'.

ii) A recording increment of approximately every 0.2 metres of tool travel should be maintained as the minimum 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.

    Where logging while drilling has been approved in place of running wireline logs, the operator is requested to record the frequency of measurement as a function of depth on any log prints generated.

iii) 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' established in accordance with Section 144 of the regulations.

Where log(s) run in open or cased hole are acquired either while drilling or by pipe conveyed means and represent the official logs for submission to the Board, such logs must be depth-tied to the 'primary depth-control log' for the well before the log can be designated as a 'final' print. Logs that have not been depth corrected, should be designated and submitted as 'field' prints. Alternatively, a composite print of openhole logs may be submitted where logs are depth-tied to the 'primary depth control log' for the well. In this instance where a composite print is submitted, as-acquired logs may be submitted as 'final' prints.

iv) If an operator generates paper copies of 'true vertical depth' logs, the Board requests that these logs be submitted in accordance with Schedule 2a of this document.

v) 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.

(b) Well Termination

The operator must provide at well termination such logs as may be requested by the CCO to assess the presence of hydrocarbons, and any potentially productive intervals before an approval to terminate the well as required by Section 177 of the regulations is granted. The operator may supply these logs in accordance with the reporting requirements for 'Special Circumstances' described in Schedule 2a of this document.

1-2.4.3 Reporting Requirements

(a) Operational Records and Reports

Section 154 of the regulations entitled 'downhole survey records' outlines the reporting requirements applicable to logs and surveys conducted in the well.

The operator is requested to provide:

i) 'field' and/or 'final' print copies of 'measured depth' logs, and where they have been generated, 'true vertical depth' logs in accordance with Schedule 2a of this document;

ii) two digital copies of all 'measured depth' logs in accordance with Schedule 2b of this document, and

iii) two digital copies, on CD, of the final directional survey in accordance with the form prescribed or agreed to by the Board.

(b) Final Well Report:

The operator is requested to provide a summary list of all logs and/or surveys run in the well as part of the final well report. Print 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 final well 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) two copies of the digital record of all SEGY and ASCII data associated with the geophysical surveys conducted. If possible, this data should be submitted on a single medium, preferably on CD or alternately on 8 mm tape.

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

1-2.5 Testing and Sampling of Formations

Section 170 of the regulations requires every formation to be 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.

1-2.5.1 Program Design

The operator is required to submit its proposed program for the testing and sampling of formations as part of its application for an ADW.
Two approaches are recognized for this purpose. These include: (a) wireline testing conducted typically in open hole and limited to small scale investigations confined to the near wellbore; and (b) formation flow testing conducted in cased hole, and designed to carry out large scale investigations beyond the influence and contamination of the near wellbore. Both approaches offer distinct advantages and limitations with respect to well evaluation.

(a) Wireline Testing

The Board requires, that where practicable, the operator survey those open hole sections of a well in which indications of porous and permeable reservoir rock exist. The operator should indicate its intent to conduct wireline testing in its ADW application and include any criteria or conditions which may apply. In development wells, such testing may be limited to those intervals that offer potential for development.

A survey should include testing of all potential reservoir intervals to confirm the existence of porous and permeable reservoir, and to record pore pressure. The operator should conduct multiple tests 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;
- verifying inter-well sand continuity in development wells; and,
- assisting in pool designations for fields undergoing development.

Where such a survey is conducted in either an exploration or delineation well, the operator will be expected to attempt to obtain representative samples of in-situ hydrocarbons and formation waters where such opportunities exist. Where fluid sampling is planned, the operator is referred to Section 175 of the regulations.

(b) Formation Flow Testing

The Board requires that the operator conduct a formation flow test where hydrocarbons are encountered within a sufficient thickness of porous and permeable reservoir rock for the purpose of acquiring representative fluid samples and pressure data to determine the in situ flow characteristics of the reservoir.

Where a formation flow test is conducted, the Board may under certain circumstances request that one of its conservation officers witness the test. Such requests have been associated with the testing of exploration wells. The Board would inform the operator of this possibility at the ADW stage and confirm with the operator later during the planning stages of the test.

- Exploration Wells

C-NOPB: *Unless otherwise approved, the operator of an exploration well will be required to conduct a formation flow test over any formation where well porosity, permeability and hydrocarbon saturation (cuttings, cores, logs and wireline tests) indicates:*

- *for a well drilled in shallow water (i.e. less than or equal to 400 metres water depth), potential pay of 5 metres within a 10 metre gross stratigraphic interval; and,*
- *for a well drilled in deep water (i.e. greater than 400 metres water depth), potential pay of 15 metres within a 50 metre gross stratigraphic interval.*

Where the testing criteria respecting pay threshold is not met, the Board will forgo its requirement to test.

Where an operator wishes to defer testing to a later date, a written request must be made to the CCO outlining the reasons for the request. Where an approval to defer is granted, the operator must suspend the well in a manner that allows the well to be re-entered and tested at a later date.

C-NSOPB: *Section 170(1) of the Drilling Regulations states that,* "… every operator shall ensure that every formation in a well is sampled or tested to obtain fluid flow and reservoir pressure data from the formation where there is an indication that the results of such a sample or test will contribute substantially to the evaluation of the formation."

The CNSOPB will review all available data (geological, geophysical, petrophysical etc.) during the drilling of the well and at the completion of drilling, prior to deciding if formation flow testing is required. Testing will be required if there is an indication that it would contribute substantially to the evaluation of the zone(s). When evaluating if formation flow testing should be required, the CNSOPB will balance the additional challenges that may be associated with testing certain exploration wells, e.g. deep-water wells, highly over-pressured wells, etc.

If approved, by the CNSOPB, an operator will be permitted to suspend the well and defer formation flow testing to a later date. In addition, operators may be permitted to defer formation flow testing to an equivalent zone in a delineation well.

- Delineation Wells

An operator will be required to plan for and conduct testing in select wells where such testing could resolve technical and/or economic uncertainities respecting the development of a pool or field. To this end an operator should submit its delineation plans to the Board in advance of any ADW's.

An operator will be required to carry out a testing program (subject to the criteria for potential pay thickness that exists for exploration wells) within select delineation wells to assess the production potential of any new hydrocarbon-bearing formations not encountered or tested in previous wells. The operator may choose to defer the testing of any new horizons until an assessment is made of the extent and potential significance of any new horizon.

- Development Wells

An operator may be required to conduct formation flow tests in select development wells for any prospective hydrocarbon bearing reservoir interval that is not targeted for development. This would likely occur in the absence of other strategies for reservoir appraisal.

In formation(s) being targeted for development, the operator will be required to conduct production testing in accordance with the Production and Conservation (P&C) Regulations. The operator is referred to Section 2-2.3 of this document for guidance related to production testing.

The operator must indicate its intent to conduct formation flow testing in its ADW application for any well type, subject to the guidance provided above, where indications exist to warrant such testing. The submission of details respecting the testing program as required by Section 171 of the regulations should be made at least 48 hours prior to initiating the test program. Any changes made to a test program within 48 hours prior to testing should be submitted as an addendum as soon as possible. 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 per metre 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;

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 the bottom hole test string 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 1-2.5.2 of this document for additional guidance regarding the details of the test program.

The proposed test program requires the approval of both the Board's Chief Conservation Officer (CCO) and Chief Safety Officer (CSO). 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 may at this time request that one of its conservation officer's witness the test.

1-2.5.2 Operational Guidance

The following guidance is provided in relation to the conduct of a formation flow test to promote consistency in meeting regulatory requirements.

(a) Safety and Training

In accordance with the requirements of Section 172 of the regulations, an operator will be expected to hold a safety meeting immediately prior to conducting a formation flow test to review testing procedures and discuss emergency response measures.

Competent personnel should be assigned to oversee testing operations to ensure:

. test objectives are met;
. complete, and accurate data collection;
. sufficient fluid samples are collected;
. on-site pressure analysis and interpretation; and,
. adequate reporting of test results.

For safety and for environmental reasons, the requirement for adequate illumination, as stated in

Section 172(2) of the regulations should be taken to mean ‘daylight’ with respect to permitting the initial flow of any fluids to surface, and/or ‘artificial lighting’ for any secondary flows associated with the same test interval. To this end, the operator’s policies on this matter should be included with the testing program submitted to the Board.

(b) Equipment Requirements

An operator is referred to Sections 16, 62, and 113 of the regulations for the requirements respecting testing equipment, and the storage and disposition of produced fluids.

Equipment employed in a test must be suitable for a comprehensive evaluation of the interval in question. An operator will be expected to resolve any operational difficulty that may be reasonably foreseen. This would include for example, being prepared to assist, using artificial lift technology, the flow of heavy hydrocarbons 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 would be expected prior to any attempt to flow the well conventionally or before introducing artifical lift to assist flow.

(c) Testing the Well

An operator is referred to Schedule 3a of this document for guidance related to the flow and shut-in periods when conducting formation flow tests on exploration, delineation and development class wells.

As a minimum requirement, a test must 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 and shut-in periods.

The sampling flow period (iv) along with the secondary flow and shut-in periods (v) are considered to be optional and may be employed at the discretion of the operator.

The Board recognises that minor deviation from the suggested drawdowns and durations indicated in Schedule 3a 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.

• 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.

As per Schedule 3a, drawdown should be minimized to prevent unnecessary shock to the formation. Shut-in duration should be of fixed duration, as indicated, to minimize any uncertainty that may arise in the estimation of initial reservoir pressure.

• 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.

Where cleanup cannot be achieved due either 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 necessary 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 fluid influx into the test string.

• 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 Schedules 3a and 3b of this document. A minimum of 4 hours stabilized flow is indicated with a maximum flow duration of 24 hours being possible. 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. This restart would not be triggered by the necessity to "rock" the choke in order to clear debris.

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 test 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. In an exploration well, added importance is attached to pressure recovery in that it provides a suggestion of size to the accumulation, and consequently to its potential for sustainable production.

Where an operator has test objectives that conflict with those outlined above, the Board requests that the operator address these objectives during the secondary flow and shut-in periods contemplated.

• 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 any optional action in pursuit of secondary flow objectives. However, if the 'Sampling Flow Period' is considered critical to test objectives, the operator is free to conduct this period prior to satisfying any regulatory based objectives.

The operator is encouraged to employ downhole fluid sampling procedures, to acquire PVT quality samples where samples obtained at surface or by wireline tests for PVT purposes are felt to be unsatisfactory.

The Board may request subsurface sampling in those oil-bearing formations where oil exists in an undersaturated state, and where samples can be acquired at sampling conditions whereby associated gas remains in solution.

• 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 Alberta Energy and Utilities Board (AEUB) Guide G-3, 'Gas Well Testing - Theory and Practice', for recommended procedures for assessing the deliverability of gas wells.

As indicated in Schedule 3a, the duration for secondary flow should not exceed 4 days, or such duration as approved by the CCO and CSO. This limitation is intended to prevent any confusion between the secondary objectives of a formation flow test and an Extended Formation Flow Test as defined under the Act which gives the operator title to the petroleum produced by such a test.

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

While it is not a requirement by regulation, 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 are recognized. The Board encourages the use of this technology in testing a well 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 recommended in Schedule 3a. Where such technology is not employed, the Board will require, unless otherwise approved by a conservation officer, that the operator adhere to the approved test program.

(e) Downhole Pressure/Temperature Gauges

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 Board will require that, where a gauge is being employed for measuring reservoir pressure and temperature for pressure analysis purposes, that an electronic gauge be used. 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. 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, regardless of the end use of such gauges, the operator ensure 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.

Schedule 4 of this document reflects the wide range of varying types of gauges currently in use.

(f) Fluid Sampling

Section 176 of the regulations requires an operator to obtain during a formation flow test a sample of each fluid produced in sufficient volumes and using techniques to permit the analysis required by the regulations.
The operator is referred to the following practices when developing its sampling program:

- API RP 44 - 'Recommended Practice for Sampling Petroleum Reservoir Fluids'; and,

- API RP 45 - 'Recommended Practice for Analysis of Oil-Field Waters'.

The Board requires 1 set of atmospheric samples consisting of samples of each liquid produced (oil, or condensate and water) from each test. Each sample should be at least of 4 litre capacity. Samples of gas produced on test should not be submitted unless specifically requested by the Board.

1-2.5.3 Deposition and Analysis of Fluid Samples

The requirements for the deposition and analysis of fluid samples from a well are found in Sections 195, 199 and 200 of the regulations.

(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.

Note: 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.

Samples obtained for the Board should be delivered within 60 days of when the sample was acquired. Samples should be shipped to the Board at the appropriate address, shown in Appendix A.

(b) Analysis of Fluid Samples

In conducting the analysis of samples as required by Section 199 of the regulations, an operator is referred to API RP 44 and API RP 45 for details respecting analysis, and the format for reporting results to the Board.

1-2.5.4 Reporting Requirements

(a) Operational Records and Reports

• Wireline Tests

The results of a wireline survey should be submitted to the Board in the form of a log or downhole survey record as required by Section 154 of the regulations and by Section 1-2.4.3 of this document. The log should include:

i) A summary section or log header consisting of a table reporting results from survey points, and a remark column. The table should provide a brief summary of all tests conducted noting depth, success of test, the result as to virgin 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.

   Remarks by service company personnel should include the serial number and make of the gauge employed and whether pressures reported in the log header have been 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 testers have been determined, the operator should provide a description of fluids recovered, noting volumes and 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.

The operator is required to submit print copies of log(s) generated in accordance with Schedule 2a of this document. In addition, two digital copies of the log, including summary data should be submitted on CD in accordance with Schedule 2b.

• Formation Flow Tests

In accordance with Section 156 of the regulations, the operator is requested to submit to the Board on a daily basis by fax, email or other such means acceptable to the CCO , one copy of all relevant information or data obtained in satisfying the requirements of Section 174 of the regulations. 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:

   . a Cartesian plot of pressure/temperature data versus time for each gauge; and,

   . 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.

Two copies of the pressure/temperature data referred to in (v) above should be submitted in digital form as ASCII files on CD. The format for data submission should be columnar: real time (hh mm ss -24 hr clock) **not** elapsed time, pressure (kPa absolute) and temperature (deg. C) separated by blank spaces, not commas.

(b) Final Well Report

As part of the final well report, the operator is requested to provide a brief summary of the results and reports associated with each formation flow test conducted. Additionally, the operator is required to submit in accordance with the requirements for the final well report, copies of:

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

ii) any fluid analysis reports of oil or condensate, gas and water samples collected from wireline surveys, or from formation flow tests conducted.

Part 2 Evaluation Guidelines - Newfoundland/ Nova Scotia Offshore Production and Conservation (P&C) Regulations

2-1 Introduction

The Newfoundland and Nova Scotia Offshore Production and Conservation (P&C) Regulations, hereafter referred to in Part 2 of this document as the regulations, apply in respect of every operator who develops a production site or produces petroleum, and every operation related to the production of petroleum in the offshore area.

The P&C Regulations provide the framework for evaluation programs pertaining to reservoir characterization and effective depletion monitoring. Part II of the regulations introduce the various subject areas for which evaluation programs are conducted under these regulations. These areas include:

. cores;
. production testing;
. pool pressure measurements & surveys;
. cased hole logs; and,
. fluid sampling & analysis.

The Board encourages an operator to submit its intentions with respect to data gathering in each of the above subject areas as a single document for the CCO's approval.

2-2 Well, Pool & Field Evaluation Programs

The guidance provided in Part 2 of this document will, in an approach similar to that taken in Part 1, focus on subject areas from the standpoint of program design, program execution, deposition and analysis of samples, and reporting requirements. Of these, the operator is asked to note the following changes respecting reporting requirements for programs.

• Reporting Requirements

The operator is required to submit, in accordance with Section 4 and 75 of the regulations, three copies to the C-NOPB and four copies to the C-NSOPB as appropriate of the results, data, analyses and schematics obtained as a result of any evaluation program carried out under Part II of the regulations.

The operator should submit this information to the Board within 60 days of completion of the program in the form and manner indicated in this document. All submissions to the Board should have a corresponding transmittal.

2-2.1 Cores

Section 11 of the regulations requires that a coring program for the pool or field be submitted and approved by the CCO prior to the commencement of development drilling.

2-2.1.1 Program Design

The coring program should reflect 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. The following considerations apply:

i) Core should be taken from a select number of development wells to minimize uncertainty with geologic correlation, reservoir characterization and the depletion scheme proposed.

An operator should plan to cut representative core from all targeted horizons:

. the entire reservoir interval for a select number of development wells;

. selected gas, oil or water-bearing intervals for select wells; and,

. where the opportunity exists to assess the performance of a depletion scheme.

ii) Coring of hydrocarbon-bearing reservoirs outside of targeted productive horizons is encouraged where the potential for development exists.

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

The Board recognizes that recent advances in array based and borehole imaging technology have been employed successfully to complement coring programs. Where an operator has established by comparison with core the benefits of such technology, the operator may seek to modify its coring program requirements in wells where such technology is employed.

(a) Program Submission to the Board

An operator is requested to submit its proposed coring program for a pool or field to the CCO at least sixty (60) days before development drilling for the pool or field is expected to commence.

The operator is encouraged to minimize the number of approvals potentially possible by submitting the coring program for the field, or by grouping together those pools common to a particular horizon.
A coring program should include the following:

i) A summary of coring to date, including the details of core cut and recovered on a well basis indicating: 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. This list should indicate 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 relative to the point of intersection with the pool or formation targeted for coring.

(b) Program Approval

The CCO will approve a coring program where the CCO is satisfied that the program provides sufficient geological and reservoir data to evaluate the pool or field.

An approved program should be executed in accordance with the drilling program submitted in support of the ADW required for each well. As development drilling progresses, it is likely that an operator may wish to revise its coring strategy to reflect current understanding and remaining uncertainty. In this circumstance:

i) where a change is proposed that involves coring and/or core analyses in addition to that of the approved program, the operator need not revise its program, but reflect any additional effort through the ADW process for the affected well;

ii) where a change is proposed that involves a reduction in coring and/or analyses in relation to the approved program, the operator must submit a revised program with appropriate support documentation for the CCO's approval.

2-2.1.2 Deposition and Analysis of Core Samples

Cores taken from a development well are subject to the requirements for deposition and routine core analyses as defined under Part VIII of the Drilling Regulations. The operator is referred to Section 1-2.2.3 of this document for guidance.

• Special Core Analyses

An operator will be required to conduct special core analysis in accordance with that prescribed in an approved coring program. Typical analyses would 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.

The necessity for such analyses will vary from pool to pool given the approach to development and the level of uncertainty that exists. In each case, the approved program will represent the minimum requirement for coring and analyses necessary for the pool or field.

2-2.1.3 Reporting Requirements

The operator is required to submit to the *CCO, of the C-NOPB (3 copies) and to the C-NSOPB (4 copies), in print form of any reports related to core obtained from the well.* The operator is required to provide the Board with two digital copies in ASCII format on CD of all data contained in these reports.

2-2.2 Production Testing

Section 12 of the regulations specifies the requirements for production testing of development wells. An operator must have its program for testing wells approved by CCO before a well(s) can be placed into production.

2-2.2.1 Program Design

In accordance with Section 12(1), the operator is encouraged to minimize the number of approvals respecting the subject area by developing and referencing a standardized program for the production/injection testing of wells. Where a standard program is approved, no further approvals respecting such testing are necessary.

The regulations require an operator to carry out production or injection testing in a development well:

i) upon initial completion of the well prior to placing the well into service, and thereafter following every recompletion of the well; and,

ii) immediately 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; or,
- suspension, abandonment or isolation of any portion of a well's completion interval.

To this end, the Board appreciates that a period of production or injection stabilization is preferable prior to conducting such testing. For producing wells, the initial production test must be conducted within 1 month of initating production (i.e. handed over to process/production) from an oil well and within 1 week for a gas well. For water injection wells, the baseline injection test must be conducted within 6 months of initiating injection into the well.

Program objectives required in accordance with Section 12 of the regulations shall 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 formation fluids;

and for injection wells:

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

When production from two or more pools or recognized zones are 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.

(a) Program Submission to the Board

Where the operator chooses to submit a standardized program for the testing of wells, this program should be submitted to the CCO at least 60 days before development drilling, for the field, is expected to commence.

Alternatively, where the operator chooses to submit customized programs for testing on a well by well basis, or, where a standard program exists and circumstances dictate that the operator deviate from standard procedures, the operator will be required to submit for approval, its program for testing the well at least 48 hours prior to the anticipated test.

The program submitted to the CCO should include:

i) details of the proposed equipment pressure tests and safety precautions to be taken prior to and during testing operations;

ii) a description of the operational procedures to be used in conducting, controlling and terminating the test, including:

. a list of all flow and shut-in periods and the proposed duration for these periods;

. a description of all fluids to be employed in conducting the test;

. proposed fluid sampling program and procedures;

. data gathering and reporting procedures; and, the method of disposal of produced fluids;

iii) a description of the equipment to be utilized in the test program, including:

. a diagram of the test string including the particulars and specifications for downhole pressure and temperature gauges; and,

. a schematic of surface equipment showing flow paths for produced fluids and any fluids employed in artificial lift operations.

Where a standard program for testing has been approved by the Board, the operator is requested to inform the Board prior to testing, of the test interval and, by referencing its program, the procedures that are to be followed.

• Conservation Requirements

Where the operator proposes to flare oil and/or gas for flow duration in excess of 24 hours, the operator is requested to provide the following information in keeping with Sections 32 and 33 of the regulations:

i) a discussion of the objectives of the test including estimates of the flow rates and volumes to be flared, and justification why extended duration testing is necessary to achieve the objectives;

ii) a discussion of options considered to conserve the oil and/or gas and why they were rejected.

(b) Program Approval

The Board's Chief Conservation Officer must have approved a production testing program for a well or field before the well can be placed into production.

2-2.2.2 Operational Guidance

(a) Testing the Well

The operator is referred to Section 1-2.5.2(c) of this document for guidance pertaining to flow and shut-in periods for formation flow tests. This guidance is similarly applicable to production tests. The secondary flow period available to the operator under a formation flow test should be taken to be equivalent to extended production testing recognized in Sections 32 and 33 of the regulations and consequently subject to conservation requirements previously discussed.

Meters and gauges used to record rates, pressures and temperatures should be calibrated yearly. Gauges used to record pressure/temperature data should be checked against a reference gauge or a dead weight tester prior to and following completion of the test. Any discrepancies should be noted in the test report.

(b) Fluid Sampling Requirements

Fluid samples are required to be taken during production testing following the initial completion of a well and thereafter upon recompletion in a new zone or pool.

The operator is referred to the requirements of this document, Section 15 of the regulations and to the guidance respecting this subject area provided in Section 2-2.5 of this document.

2-2.2.3 Reporting Requirements

In accordance with Section 12(6) of the regulations, the operator must upon conclusion of a production test, submit where requested to CCO on a daily basis by fax, email or other such means acceptable to the Board, one copy of all relevant information relating to the results of the test. The operator should submit these results to the Board in accordance with the guidance for operational records and reports for formation flow tests as set out in Section 1-2.5.4(a) of this document.

The operator is required to submit to the CCO final reports related to the results or analyses of any production tests. The following number of print *copies are to be submitted no later than 60 days following the conclusion of the test:*

C-NOPB: three copies
C-NSOPB: four copies.

Pressure data associated with production testing should be submitted to the Board as ASCII files on CD. The format for data submission should be columnar: real time (hhmmss - 24 hr clock) **not** elapsed time, pressure (kPa absolute) and temperature (deg. C) separated by blanks not commas.

2-2.3 Pool Pressure Measurements and Surveys

Section 13 of the regulations sets out the requirements for pool pressure measurements and surveys in development wells. These requirements play an integral part in the reservoir management of a pool or field during its operational life.

The guidance provided in this section has been obtained in part from:

- AEUB Guide G-40, 'Pressure and Deliverability Testing Oil and Gas Wells'.

2-2.3.1 Program Design

Under Section 13 of the regulations, the operator of a field is required to:

- determine for each development well, the initial pressure of the pool upon completion, prior to commencing production from the interval; and,
- carry out an annual pool pressure as approved by the CCO.

(a) Pool Pressure at a Well upon Completion

This measurement not only provides the baseline for initial pool pressure, but assists the identification and delineation of pools 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 wireline survey for the well (described under section 1-2.5 of this document) where it exists 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 production test conducted for the well.

Where a wireline survey was not conducted, the initial pressure of the pool should be determined following well backflow or as part of the production test where it is conducted prior to placing the well on production (i.e. handover to process/production).

(b) Annual Pool Pressure Survey

This survey must be carried out in accordance with the program submitted by the operator and approved by the CCO. In fields where multiple pools exist, the operator is encouraged to minimize the number of submissions wherever possible by grouping survey programs together under a single submission.

The Board is sensitive to an 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 designing its annual pool pressure survey program:

i) Wells surveyed should provide an accurate indication of the pressure distribution within a pool, and for the field.

ii) Wells in high and low pressure areas in which a pressure maintenance scheme exists should be surveyed each year until the problem is corrected.

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.

v) Wells in areas where pressure levels, pool boundaries and pool continuity are uncertain, or where anomalous pressure trends exist should be surveyed.

The following wells are recognized as being good candidates for surveying:

- wells in which an open hole wireline survey was conducted;
- wells subject to either a production, or injectivity test;
- suspended wells; and,
- wells subject to scheduled or unscheduled downtime.

The operator is required to submit its program for a pool pressure survey to the CCO at least 60 days prior to conducting the survey. The 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 the gauge calibration plan.

The Board recognizes that requiring lead time of 60 days could result in lost opportunities for the operator to conduct its survey. Consequently, the Board will make every effort to minimize the time between submission and approval of a survey program. The Board will accept the valid results of any survey conducted without prior approval during this time provided the well(s) concerned were included in the survey application and were subsequently approved as part of the overall pool survey approval. Where permanent downhole gauges are used (see Section 2.2.3.2a of this document *Recommended Practices for Gauges - Use of Permanent Downhole Gauges)*, the CCO will consider an alternative program for pressure data acquisition and reporting on a case by case basis. Approval of the survey program will be subject to the CCO being satisfied that it provides for the accurate determination of the static pressure in the pool.

2-2.3.2 Operational Guidance

(a) Recommended Practices for Gauges

The following practices are recommended when conducting a pressure survey. These practices have been adopted from AEUB Guide G-40, ‘Pressure and Deliverability Testing Oil and Gas Wells’.

i) Pressure gauges should be selected such that expected pressures fall between 60 and 90 percent of a gauge's rated pressure range.

ii) 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.

iii) To minimize the introduction of errors, thesame gauges should be used where multiple surveys or tests are to be conducted in a well.

iv) All pressure measurements should be made to the reference depth for all measurements as agreed to by the CCO and the operator.

v) 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 by taking measurements at 30 metre intervals over the last 150 metres covered.

vi) 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. The stretch incurred should not exceed the following tolerances suggested as a function of run depth.

Run Depth (mRef)	Stretch (m)
600	0.3
1200	0.6
1800	1.2
2400	2.1
3000	4.2
3600	7.5

Where these tolerances are exceeded, conditions that may have caused slip or elastic deformation of the running medium should be reported.

vii) The maximum temperature thermometer should be read and the reading recorded after each gauge has been retrieved from the well.

viii) 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

Where the operator wishes to employ permanent downhole gauges for use in pressure measurements and pool surveys, the operator must obtain approval from the CCO prior to their installation.

These gauges must be checked for measurement reliability whenever indications exist which warrant such action. To this end, an operator may be required 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) Production/Injection Test Data

Where survey data results from either a production or injection test, the following criteria should be satisfied:

i) the test should be mechanically sound and operationally successful;

ii) where the test takes place upon initial completion of a pool, the pressure to be used in the survey should be based upon the extrapolated pressures from two shut-in periods that fall within one percent of each other;

iii) where the test takes place during the producing life of the pool, the pressure to be used in the survey must, after extrapolation, fall within five percent of the last pressure survey conducted for that location.

iv) a minimum of two gauges must be employed in gathering the pressure data.

2-2.3.3 Reporting Requirements

• Pool Pressure Survey Report

The operator is required to submit annually, to the CCO*, a pool pressure survey containing flashpoint analysis in addition to discussion and analysis of reported pressures, together with an isobaric map of these pressures corrected to datum depth. The following number of print copies are to be submitted to the Board:*

C-NOPB: three copies
C-NSOPB: four copies.

The operator is referred to Schedule 5 of this document for the procedure for correcting pressures to datum depth.

• Pressure Data

Where pressure data is acquired, either in association with pressure measurements taken upon completion of a well, or in association with the annual pool pressure survey, two copies of this data, in digital form, are requested by the CCO.

The above pressure data should be submitted as ASCII files on CD. The format for data submission should be columnar: real time (hh mm ss -24 hr clock) **not** elapsed time, pressure (kPa absolute) and temperature (deg. C) separated by blank spaces, not commas.

2-2.4 Cased Hole Logs

Section 14 of the regulations requires the operator of a well to run a cased hole log if it is technically feasible to do so and the log would contribute significantly to the evaluation of the pool in which the well is located.

2-2.4.1 Program Design

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

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

Such logging will be necessary in satisfying the requirements for evaluation, monitoring and efficient recovery of petroleum from wells as set out in Part III of the regulations.

Details specific to an operator's proposed program for cased hole logging should be contained within its reservoir management strategy for a pool or field submitted in support of the development plan for the field. The Board recognizes the additional challenge associated with 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 workover puurposes) in an effort to minimize disruption while the field is producing. The Board would seek to minimize production disruption by reacting only in response to significant changes in well performance indicated through routine well monitoring that may result in waste.

An operator may conduct cased hole logging operations as necessary in a development well without filing for an 'Approval for a Well Operation' providing the conditions as set out in Section 18 of the regulations are met, and the details specific to the procedures associated with cased hole logging operations have been approved under the 'Well Operation Program Authorization' detailed under Section 17 of the regulations.

• Cement Evaluation Logging

Unless otherwise approved, the operator will be required to evaluate the quality of cementation of production casing (or liner) to confirm compliance with the requirement for zonal isolation specified in Section 22 of the regulations.

The logging tool employed should be capable of providing an assessment of the quality of the cement bond both to pipe and to the formation. The tool should preferably be capable of detecting channels in the cement that might act as pathways for fluids produced from or injected into a pool.

The operator will be required to conduct logging:

- prior to the initial completion of the well; and,
- thereafter, as necessary, during the operational life of the well, when channeling is suspected, or to assess the effectiveness of well fluid control measures.

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.

• Production Logging

An operator will be required to carry out production logging to acquire a flow profile where multiple reservoir units comprise the completed interval. Such profiles should be acquired to assess contributing intervals, detect thief zones, identify water breakthrough and assist in planning workover 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 casing flow diameter.

Unless otherwise approved, an operator will be required, to carry out production logging, where practicable, on all development wells:

. to provide baseline survey data following initial completion or recompletion of the well; 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.

Unless otherwise approved, initial baseline production logging is to be conducted as soon as possible, not exceeding 1 month following production from an oil well or 1 week following production from a gas well. Similar requirements exist for injection wells, within 1 month for water injectors and within 1 week for gas injectors.

• Saturation Logging

An operator will be required to carry out saturation logging to provide profiles of fluid saturation in the well. Such profiles are 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 often the case in fields under waterflood.

Unless otherwise approved, an operator will be required, to carry out saturation logging, where practicable, on any producing development wells:

. to provide baseline survey data following initial completion or recompletion of the well;

. thereafter, as necessary, during the life of a well to monitor flood front advancement, or to support the design and assessment of workover strategies;

. at the end of the operational life of a pool or field for the purpose of quantifying remaining hydrocarbons.

Unless otherwise approved, initial baseline saturation logging is to be conducted as soon as possible, not exceeding 1 month following production from an oil well or 1 week following production from a gas well.

Saturation logging should be used where necessary in association with production logging tools to pinpoint water production and assess water injection profiles.

2-2.4.2 Operational Guidance

The operator is referred to the relevant guidance provided under the heading 'Logging Operations' covered in Section 1-2.4.2 of this document.

2-2.4.3 Reporting Requirements

For each cased hole log run in a development well the operator is required to submit to the CCO, the following number of print copies within 60 days of running the log:

C-NOPB: three copies
C-NSOPB: four copies

The Board requires that two digital copies of this data be submitted and be in agreement with the 'final' print copies of logs submitted. The submission of digital data is to be made in the form and manner indicated in Schedule 2b of this document.

2-2.5 Fluid Sampling and Analysis

Section 15 of the regulations specifies the requirements for fluid sampling and fluid analysis respecting development wells.

2-2.5.1 Program Design

The regulations require an operator of a development well to collect fluid samples from a pool:

- upon completion of the well in a pool, where sampling could contribute to the evaluation of the 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.

(a) Sampling at Well Completion

The operator of a well is required 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 production test by either subsurface or surface sampling means. Samples collected 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 is required to obtain and analyze samples of oil, gas and water collected at the surface from a sufficient number of wells completed in that pool to determine the composition of fluids at least once every 12 months, or whenever 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 production 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 may collect samples from producing wells, during the routine testing of these wells for monthly proration of production, and at any time for injection wells by sampling the fluid streams being injected into a pool.

Adequate sampling of injection wells is required where gas and the knowledge of its composition is critical to a depletion scheme, and where quality control of injection water is required. Fluid injection streams should be sampled at, or as close as possible to wellheads.

Aside from the annual sampling requirements for a pool, the operator is required to obtain fluid samples, and carry out the appropriate analyses whenever there is reason to believe that the composition of a fluid produced from a pool has changed. Such action should be taken:

i) when a significant change is experienced in the water cut, or gas/oil ratio of a well; or,

ii) when the composition of fluids produced from or injected into the pool has changed.

- Sampling of Group and End Use Streams

The operator is encouraged to sample and analyze the following group and end use fluid streams as part of the annual sampling program where sampling would contribute to the evaluation of the pool or field:

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; and,

ii) secondary streams, e.g. produced water discharge, and gas used for fuel, for gas lift and gas flared.

(c) Sampling of Produced Water

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

For this purpose, an operator must be able to detect during production or proration testing, the presence of water in combination with oil, either directly as a result of 3-phase separation, or indirectly through real time monitoring of a 2-phase oil/water stream. Where indications suggest water production, the operator is required to sample the fluid stream to confirm the production of water, and if confirmed, obtain a representative sample for analysis. In ascertaining the probable source of this water, it is recommended that the operator obtain:

i) representative samples of formation water from all wells encountering water-bearing reservoir within pool(s) approved for development;

ii) representative samples of formation water from all water-bearing horizons outside of pools approved for development; and,

iii) representative samples of water injected into a pool.

The operator is encouraged to acquire the above data early in the life of a pool or field to provide an effective data base to assist in the determination of the source of any produced water, and in support of taking remedial action that may become necessary.

2-2.5.2 Operational Guidance

(a) Fluid Sampling

The operator is required to conduct fluid sampling in accordance with the practice recommended in the following standards:

. API RP 44, 'Recommended Practice for Sampling Petroleum Reservoir Fluids';

and,

. API RP 45, 'Recommended Practice for Analysis of Oil-Field Waters'.

The Board does not typically require the submission of fluid samples from development wells. Exceptions would include those cases where fluid composition deviates substantially from the norm, or where the operator conducts formation flow testing over horizons not approved for development. In such cases, the operator should refer to Section 1-2.5.2(f) of this document.

2-2.5.3 Deposition and Analysis of Fluid Samples

The deposition of fluid samples from a development well should follow the requirements of Part VIII of the Drilling Regulations, and the guidance regarding deposition provided in Section 1-2.5.3 of this document.

• Fluid Analysis

Analysis of fluid samples from development wells must be carried out in accordance with Section 15 of the regulations.

Analyses conducted pursuant to Sections 15(1), (2) and (4) must be carried out in accordance with API RP 44 and 45. 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 routinely 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.

The results of these analyses are to be submitted to the CCO in accordance with the reporting requirements set out below.

Other types of analyses that may be carried out include:

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

The results of these analyses need not be submitted, but should be available for review by the CCO or one of the Board's conservation officers on request.

The operator is referred to Schedule 6 of this document when satisfying Section 15(6) of the regulations. This schedule summarizes the compositional and physical property requirements of Section 11.07 of the Oil and Gas Regulations of Alberta.

2-2.5.4 Reporting Requirements

All fluid sampling information and analyses results must be submitted to the CCO, within 60 days of acquiring the fluid sample in question. The operator is responsible for keeping the Board informed in writing respecting any delays related to the reporting of results. The following number of print copies are required:

C-NOPB: three copies
C-NSOPB: four copies.

Two digital copies of this data set are required to be submitted to the CCO as an ASCII file on CD.

Disclosure of Information

Information or documentation, which includes samples, data, records and reports submitted to the Board in compliance with Parts 1 and 2 of this document may be disclosed to any interested third party in accordance with Section 119 of the Canada-Newfoundland Atlantic Accord Implementation Act (C-NAAIA), Section 114 of the Canada-Newfoundland Atlantic Accord Implementation Newfoundland Act (C-NAAINA), Section 122 of the Canada-Nova Scotia Offshore Petroleum Resources Accord Implementation Act (C-NSOPRAIA) and Section 121 of the the Canada-Nova Scotia Offshore Petroleum Resources Accord Implementation (Nova Scotia) Act (C-NSOPRAI(NS)A).

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.

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 as approved by the CCO. This date is typically triggered upon the completion of testing of the completed interval, and should coincide 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 as Schedule 7 within this document.

Appendix A

Relevant Addresses for the Submission of Materials and Information

All records and reports required by the Board should be forwarded to the appropriate address below:

Canada-Newfoundland Offshore Petroleum Board (C-NOPB)
Suite 500, TD Place
140 Water Street
St. John's, Newfoundland
A1C 6H6

Contact: Administration Department
Phone: (709) 778-1400
Fax: (709) 778-1473

Canada-Nova Scotia Offshore Petroleum Board (C-NSOPB)
Data Archive and Core Storage Facility
201 Brownlow Avenue, Suite 27
Dartmouth, Nova Scotia
B3B 1W2

Contact: Mary Jean Verrall
Title: Archive and Laboratory Supervisor
Phone: (902) 468-3994
Fax: (902) 468-4584

Any physical samples for the Board should be delivered to the appropriate address below:

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

Contact: Administration Department
Phone: (709) 778-1400
Fax: (709) 778-1473

Canada-Nova Scotia Offshore Petroleum Board (C- NSOPB)
Data Archive and Core Storage Facility
201 Brownlow Avenue, Suite 27
Dartmouth, Nova Scotia
B3B 1W2

Contact: Mary Jean Verrall
Title: Archive and Laboratory Supervisor
Phone: (902) 468-3994
Fax: (902) 468-4584

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

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

Contact: Allan Scott
Title: Head, Core & Sample Library
Phone: (403) 292-7057

Appendix B

Reference Standards and Guidelines

. API RP 13G, "Recommended Practice - Standard Procedure for Drilling Mud Report Form", Third Edition, December 1, 1991.

. API RP 31A, "Recommended Practice and Standard Form for Hardcopy Presentation of Downhole Well Log Data", First Edition, August 1997.

. API RP 44, "Recommended Practice for Sampling Petroleum Reservoir Fluids", Revised April 2003. Available through Global Engineering Documents, 15 Inverness Way East, Englewood CO 80150 USA. Phone (800) 854-7179, http://global.ihs.com

. API RP 45, "Recommended Practice for Analysis of Oil-Field Waters", Third Edition, August 1998.

. API RP 66, "Recommended Digital Log Interchange Standard (DLIS), Version 2.00", June 1996.

. AEUB Guide G-3, "Gas Well Testing - Theory and Practice", 4th Edition (SI units), 1979.

. AEUB Guide G-40, "Pressure and Deliverability Testing Oil and Gas Wells - Minimum Requirements and Recommended Practices", 3rd Edition, 1999.

Appendix C

Schedule 1
Mud Log
(example)

The following criteria are suggested for the 'Mud Log' referenced in Section 1-2.3 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.

Appendix C

Schedule 2a
Downhole Logging & Survey Records
Hardcopy Data - Reporting Requirements

Format: The Board requires that the operator submit print copies of all logs and surveys in accordance with the format defined under API RP 31A - ' Recommended Practice and Standard Form for Hardcopy Presentation of Downhole Well Log Data'.

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

. Print 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 (C-NOPB): *'Field' prints:* *1 copy for Exploration, Delineation and Development wells.*

'Final' prints: *3 copies for Exploration, Delineation and Development wells or as otherwise required in the ADW approval.*

Copies (C-NSOPB): *'Field' prints:* *1 copy for Exploration, Delineation and Development wells.*

'Final' prints: *4 copies for Exploration, Delineation and Development wells.*

Where a log(s) requires no further processing, the operator may designate such a log(s) as 'final'. In such cases, the operator need only comply with the copy requirements for 'final' prints as indicated above. Otherwise, where subsequent processing is required, the operator should submit those copies of 'field' prints with copies of 'final' prints to follow. All log prints must be clearly marked on the log header as to whether they are 'field' or 'final' prints. 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 copies of log prints 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 terminate a well is required; the operator may be required to provide logs, in advance of print copies, by FAX, E-mail or by other agreed upon means.

Appendix C

Schedule 2b
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. checkshot, 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 a single medium preferably CD or alternatively as a low density stream (2/5 GB) on 8 mm tapes.

(b) As a subset of the complete data set, representing the optical curves presented on 'final' prints. This data should be submitted preferably in accordance with the Canadian Well Logging Society's LAS 3.0 or alternatively LAS 2.0 format. The medium for submission is CD.

(c) MDT header summary data and deviation surveys should be submitted in ASCII format on 3.5 inch floppies or on CD.

(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' prints submitted to the Board. See depth-shifting requirements 1-2.4.2.(b)(iii).

Copies: Two (2) copies of the digital data set are required. 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, ftp site or by other agreed upon means.

Appendix C

Schedule 3a
Formation Flow Testing Guidelines - Period Based Objectives

Period	Status	Drawdown % of Pi	Period Duration	Objectives
i) Initial Flow	Mandatory	< 20%	5 - 10 mins	Relieve supercharging within invaded zone.
Initial Shut-in	Mandatory	n/a	90 mins	Determine initial reservoir pressure.
ii) Cleanup Flow	Mandatory	≤ 40%	As Required	Establish flow of in situ fluids at surface.
iii) Primary Flow	Mandatory	< 40%	4 - 24 hours	Produce in situ fluids at stabilized rates. Acquire representative fluid samples.
Primary Shut-in	Mandatory	n/a	8 - 48 hours	Acquire buildup data to identify flow behaviour and determine reservoir characteristics.
iv) Sampling Flow	Optional	< 5%	As Required	Acquire sub-surface fluid samples.
v) Secondary Flow	Optional	< 60%	Up to 4 days	Address additional operator objectives.
Secondary Shut-in	Optional	n/a	As Required	Address additional operator objectives.

Appendix C

Schedule 3b
Flow Testing Guidelines - Primary Flow Period

The operator is referred to the following operational guidelines when conducting the primary flow period of a formation flow test. 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.

Primary Flow Period Objective: Achieve a stabilized rate of flow within the percent drawdown recommended in Schedule 3a.

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 C - Schedule 4
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 range Cost	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 1: These are estimated figures based on published literature and manufacturers' commercial data.
* Three key elements for successful testing, after Ehlig-Economides et al., *Oil and Gas Journal*, July 25th, 1994.

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

Appendix C

Schedule 5
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 C

Schedule 6 - Fluid Analyses Requirements

The following requirements for fluid analyses reflect those of Section 11.07 of the Oil and Gas Conservation Regulations of Alberta as referenced in Section 15 of both the Newfoundland and Nova Scotia Offshore Area Production and Conservation Regulations.

<u>Oil</u>

- 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.

<u>Gas</u>

- 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 deg 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.

<u>Condensate</u>

- 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.

<u>Gas and Condensate Combined</u>

- 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.

<u>Water</u>

- 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.

Appendix C

Schedule 7 - 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 preogram;
- any oil, gas and water analysis resulting from the well's initial completion program;
- Final Well 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 production or injectivity testing conducted on zones or pools 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

Final Well Report
Reporting Requirements related to Evaluation Programs

A 'final well report' is a requirement of Section 201 of the Drilling Regulations. The reporting requirements specific to well evaluations have been described within the guidance provided in Part 1 of this document, and have been consolidated in this appendix in the format suggested for a final well report. The operator is referred to the following guideline documents for the reporting requirements for a final well report specific to other program areas:

C-NOPB: *Drilling Program Authorization Guidelines - (Draft)*

C-NSOPB: *Geophysical and Geological Programs in the Nova Scotia Offshore Area - Guidelines for Work Programs, Authorizations and Reports*

An operator is required to submit to the C-NOPB, unless otherwise approved in the ADW, three (3) print copies of the Final Well Report for exploration, delineation and development wells. An operator is required to submit, to the C-NSOPB, four (4) print copies of the Final Well Report for exploration, delineation and development wells. Where secondary reports exist which are relevant to the information required in the final well report, such reports should be submitted upon completion of work with an accompanying transmittal.

In addition to the ‘print’ copy requirements outlined above, the operator is requested to submit, on CD, one copy of the Final Well Report and any secondary reports in Adobe ‘pdf’ format. The intent of the PDF copy is to investigate the possibility of reducing the number of print copies required. The operator is also requested to submit, on CD, two copies of any digital data collected in support of the Final Well Report or any secondary reports submitted to the Board. This data should be submitted in the manner prescribed by the Board.

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

Geology (All 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 should be included showing the core number, interval, and amount of recovery. The storage location of conventional core should be indicated.

For sidewall core: a table should be included 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 this effect should be included.

Well Evaluation (All 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. Mud Loggers Report, and,
- the records respecting the drilling fluid system for each phase of the hole (refer to API 13G - 'Recommended Practice - Standard Procedure for Drilling Mud Report Form', Third Edition, December, 1991).

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. Print copies of 'final' logs not submitted previously should be submitted at this time.

Appendix D (cont'd)

Final Well Report
Reporting Requirements related to Evaluation Programs

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 (Development Wells)**

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, Initial Production/Injection Test Results**

A brief summary of the results and reports associated with each formation flow test conducted or each initial production/injection test conducted should be included. 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.

Appendix D (cont'd)

Final Well Report
Reporting Requirements related to Evaluation Programs

Appendices to the Final Well 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 and/or initial production/injection testing
xiii) Oil, gas and water analyses.
iv) Completion data such as tubing and stimulation records.
v) Composite well records.
xvi) Final survey plan.

* Pursuant to Section 119 of the *Canada-Newfoundland Atlantic Accord Implementation Act (C-NAAIA)* and Section 122 of the *Canada-Nova Scotia Offshore Petroleum Resources Accord Implementation Act (C-NSOPRAIA)* this information will be kept confidential for five years.