

OIL AND GAS REVIEW REPORT



DECEMBER 2014

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1. Introduction

1.1 General

The Alberta Securities Commission (ASC) presents its tenth annual oil and gas review report (Report) that consists of data, observations and analysis of public disclosure attributed to issuers that report under National Instrument 51-101 *Standards of Disclosure for Oil and Gas Activities* (NI 51-101). The Report sets out both the general disclosure standards and specific annual disclosure requirements for reporting issuers (RIs) with oil and gas activities. The disclosure used in this Report is primarily from reporting cycle 10¹ (Cycle 10), complemented with select observations from disclosure attributed to reporting cycle 11² (Cycle 11). It is anticipated that with the provision of timely insight into current disclosure and various topics of interest, this Report will assist RIs with the preparation and disclosure of high-quality, compliant information for the benefit of all capital market participants.

Alberta is the second largest capital market in Canada³. In 2013, the oil and gas industry represented almost 25 per cent of Alberta's gross domestic product⁴. At December 31, 2013, the ASC was the principal regulator for approximately 353 RIs⁵ with oil and gas activities as defined by NI 51-101. These issuers represented approximately 72 per cent of the total number of Alberta-based RIs listed on the Toronto Stock Exchange and TSX Venture Exchange, and approximately 57 per cent⁶ of the province's aggregate market capitalization. Concurrently, Canadian RIs with oil and gas activities represented approximately 10 per cent of the listed issuers on these exchanges and about 16 per cent of their total market capitalization.

The ASC has consistently led the development and maintenance of a regulatory standard that provides investors with the information necessary to make investment decisions relative to the Canadian oil and gas industry. The *Securities Act* (Alberta) ensures that Alberta's capital market operates fairly and efficiently, providing investors access to timely and accurate information. To this end, the ASC encourages effective and compliant oil and gas disclosure, based upon the provision of balanced, authentic, relevant and reliable information. NI 51-101 is a cornerstone of this approach and currently requires annual disclosure under:

- Form 51-101F1 *Statement of Reserves Data and Other Oil and Gas Information*;
- Form 51-101F2 *Report on Reserves Data by Independent Qualified Reserves Evaluator or Auditor*;
- Form 51-101F3 *Report of Management and Directors on Oil and Gas Disclosure*; and
- Form 51-101F4 *Notice of Filing of 51-101F1 Information*.

On December 4, 2014, amendments were published to NI 51-101, its related forms and the Companion Policy 51-101CP *Standards of Disclosure for Oil and Gas Activities* (Companion Policy) with an effective date of July 1, 2015. The amendments are discussed in this Report, along with recent updates to the Canadian Oil and Gas Evaluation Handbook (COGE Handbook) comprising the detailed guidelines for estimation and classification of bitumen resources and the guidelines for estimation and classification of resources other than reserves.

1 Financial year-ends between December 1, 2012 and November 30, 2013

2 Financial year-ends between December 1, 2013 and November 30, 2014

3 The MiG Report, December 2013, TMX Group

4 Highlights of the Alberta Economy 2014, Alberta Government

5 ASC data

6 The Alberta Capital Market: A Comparative Overview - 2014 Report - Alberta Securities Commission May 2014

1.2 Executive Summary of Observations and Findings

The ASC's Petroleum Department reviews continuous disclosure from RIs with oil and gas activities, comprising both general and required annual disclosure. Through these reviews, the ASC identifies and addresses deficiencies, including errors, omissions and potentially misleading information. RIs that are uncertain whether their disclosure is compliant with NI 51-101 are encouraged to seek appropriate professional advice.

Specific frequent deficiencies were identified during Cycle 10. Three of these are noted below and are discussed in more detail elsewhere in this Report, along with additional, notable deficiencies.

- **Contingent resources and prospective resources** – An absence of or inadequate discussion of risks and uncertainties associated with the recovery of resources other than reserves; the use of boilerplate language rather than a discussion tailored to the particular RIs' circumstances; unclear geographic location of resources other than reserves and ambiguous ownership interests.
- **Reserves reconciliations** – The disclosure of negative volumes in categories that should only have positive volumes; closing balances from the prior year that are missing or are not equal to the opening balances for the current year; and missing explanations for individual reserves change categories, particularly in instances where significant changes have occurred.
- **Type wells** – Type wells (type curves) and associated information, including recoverable volumes and economics, are increasingly being disclosed, particularly in news releases, corporate presentations and prospectuses. There is frequently an absence of information with respect to the source of the material and details regarding its preparation. Associated recoverable volumes are also often not classified with regard for the applicable terminology and categories as set out in the COGE Handbook.

On October 17, 2013, the Canadian Securities Administrators (CSA) published proposed amendments to NI 51-101, its related forms and the Companion Policy (Proposed Amendments) and initiated a 90 day comment period in response to both the CSA's observations of RI disclosure and industry feedback. The final amendments (Final Amendments or Amendments) were published on December 4, 2014 and have an effective date of July 1, 2015. The Amendments promote improved disclosure of resources other than reserves and associated metrics, provide increased flexibility for oil and gas issuers that operate and report in different jurisdictions and recover previously unrecognized product types, and align NI 51-101 with the recently amended COGE Handbook.

The COGE Handbook, prepared by the Society of Petroleum Evaluation Engineers (SPEE), Calgary Chapter, is the technical standard for the evaluation of reserves and resources other than reserves for disclosure under NI 51-101. The COGE Handbook was updated twice in 2014; detailed guidelines for estimation and classification of bitumen resources (Bitumen Guidelines) became effective April 1, 2014 and guidelines for estimation and classification of resources other than reserves (ROTR Guidelines) went into effect on July 17, 2014. These updates were mainly a response to a dynamic oil and gas industry.

1.3 Cycle 10 Disclosure Commentary

The inaugural NI 51-101 reporting cycle (Cycle 1) included oil and gas disclosure associated with RI financial year-ends between December 1, 2003 and November 30, 2004. This Report focuses on oil and gas disclosure associated with RI financial year-ends between December 1, 2012 and November 30, 2013 (Cycle 10), and is supplemented with select observations from disclosure attributed to Cycle 11 (December 1, 2013 to November 30, 2014).

The oil and gas industry has undergone a major transformation over the last 10 reporting cycles. This transformation has affected most Canadian RIs with oil and gas activities and can be attributed mainly to the widespread application of technologies such as horizontal drilling, massive hydraulic fracturing stimulations, and enhanced oil recovery. This has in turn initiated changes in oil and gas resource guidance and legislation, including the recent updates to the COGE Handbook and the Amendments.

Horizontal drilling and massive hydraulic fracturing stimulations were in limited use during Cycle 1, and have now supplanted traditional vertical wells and low tonnage stimulations as the technologies-of-choice in most new oil and gas developments. This has facilitated the exploitation of low permeability shales and siltstones, which previously were generally technologically inaccessible. These technologies are also increasingly being applied to established reservoirs, enabling more efficient and improved recovery of hydrocarbons in some cases.

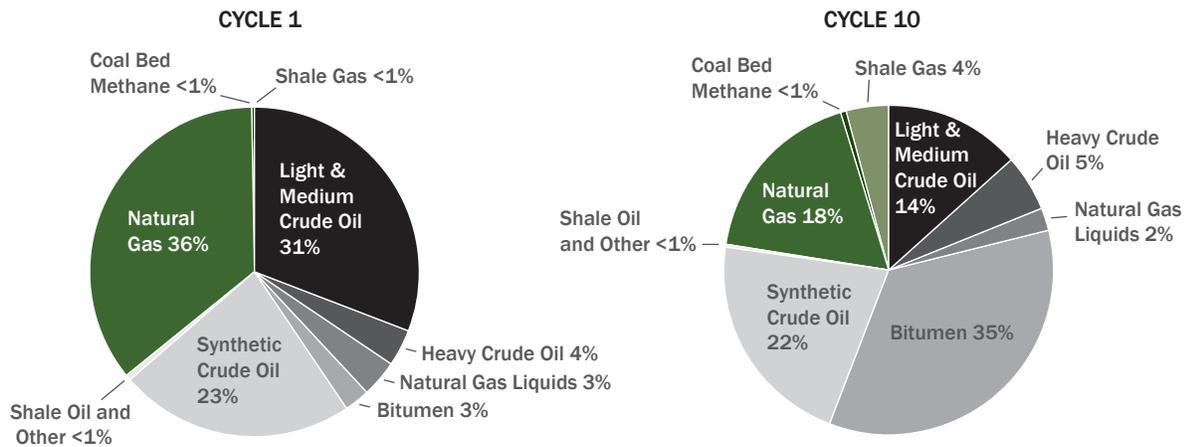
The availability and use of new technologies is reflected in the increased volumes of reserves and resources other than reserves assigned to individual wells, properties and RIs. The total volume of proved plus probable reserves disclosed by all RIs has increased greater than four-fold over the last 10 reporting cycles⁷.

Figure 1 compares total proved plus probable reserves volumes by product type reported (see section 1.1(h) of NI 51-101) in Cycle 1 with that of Cycle 10. Utilizing information compiled from available annual disclosures from all RIs with oil and gas activities, the percentage product type composition of the total volume of gross⁸ proved plus probable reserves is shown for each cycle. Differences in product type disclosure between the two cycles are attributed in part to the availability and widespread use of new and improved technologies.

7 ASC data

8 As defined in CSA Staff Notice 51-324 *Revised Glossary to NI 51-101 Standards of Disclosure for Oil and Gas Activities*

FIGURE 1 GROSS PROVED PLUS PROBABLE RESERVES VOLUMES BY PRODUCT TYPE



Percentages are based on BOEs, converted at 6 Mcf:1 bbl

As shown in Figure 1, the relative growth in percentage of bitumen volumes from Cycle 1 to Cycle 10 has outstripped growth in all other product types. Although volumes of natural gas, light and medium crude oil and natural gas liquids (NGLs) have grown volumetrically, this growth has been masked by the massive increase in bitumen volumes. Heavy crude oil and shale gas are the only other product types that have grown in percentage terms from Cycle 1 to Cycle 10, with shale oil and other, and coal bed methane remaining static.

2. Cycle 10 Observations and Deficiencies in Disclosure

2.1 Overview

Several deficiencies in disclosure were identified by the Petroleum Department during Cycle 10; the deficiencies that occur most frequently are described below. With the additional guidance available in the Bitumen Guidelines and the ROTR Guidelines, and with the publication of the Amendments in December 2014, the ASC anticipates improvements in both quality and compliance of disclosure. Deficiencies involving contingent resources and prospective resources, reserves reconciliations, type wells and petroleum losses in foreign jurisdictions are discussed in additional detail elsewhere in this Report.

- **Contingent resources and prospective resources** – The absence or inadequate discussion of risks and uncertainties associated with the recovery of resources other than reserves; the use of boilerplate language rather than a discussion tailored to the particular RI's circumstances; unclear geographic location of resources other than reserves and ambiguous ownership interests – the terms “net” and “gross” are not consistently applied or applied in a manner consistent with their definition in CSA Staff Notice 51-324 *Revised Glossary to NI 51-101 Standards of Disclosure for Oil and Gas Activities*, which defines gross as issuer working interest before the deduction of royalties excluding royalty interests and net as issuer working interest after the deduction of royalties and including royalty interests.
- **Reserves reconciliations** – The disclosure of negative volumes in categories that should only have positive volumes; closing balances from the prior year missing or not equal to the opening balances for the current year; and missing explanations for individual reserves change categories, particularly in instances where significant changes have occurred.
- **Type wells** – An absence of information with respect to the source of the disclosure and details regarding the preparation of type well information. Associated recoverable volumes are often not classified with regard for the applicable terminology and categories as set out in the COGE Handbook. Also, net present values disclosed without the associated category of reserves and resources other than reserves.
- **Petroleum losses in foreign jurisdictions** – Disclosure from RIs is frequently inadequate regarding the theft and trade of produced petroleum acquired from field operations, pipelines, export terminals and commercial shipping vessels in foreign jurisdictions.
- **Terminology and categories of reserves and resources other than reserves** – Disclosure of reserves and resources other than reserves sometimes occurs without regard for the applicable terminology and categories as set out in the COGE Handbook, particularly in news releases and corporate presentations.
- **Drilling locations** – The categories of reserves and resources other than reserves attributed to disclosed drilling locations, and the sources of the estimates are often lacking, particularly in news releases and corporate presentations.
- **Irregular disclosure of resources other than reserves** – Some issuers disclose resources other than reserves with reduced or sporadic frequency and without accompanying explanation.

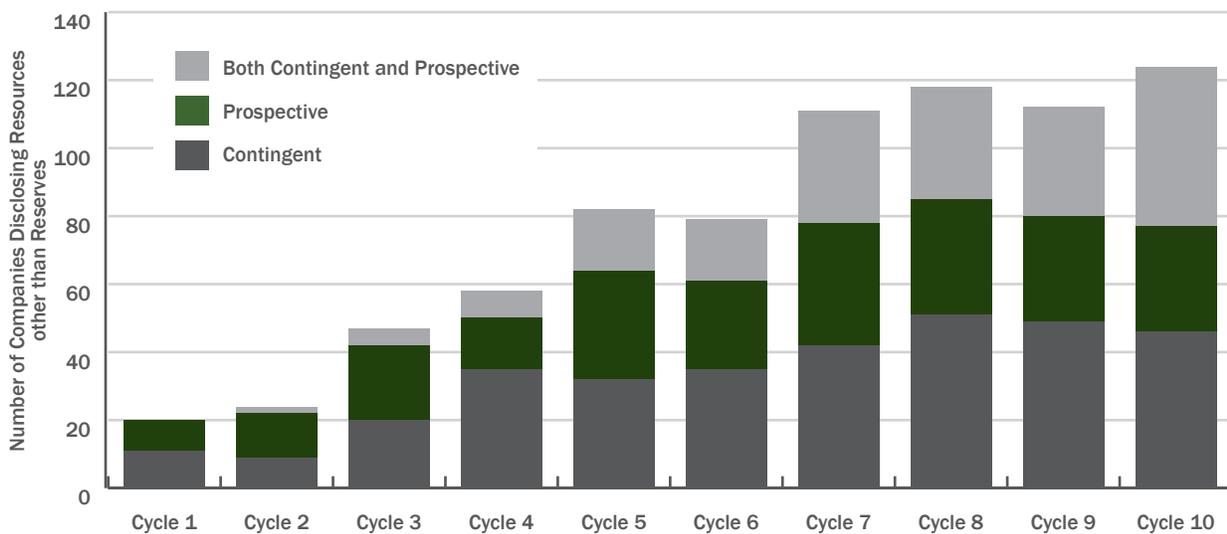
2.2 Contingent Resources and Prospective Resources

Under NI 51-101, the disclosure of resources other than reserves is optional, except with respect to

prospectus offerings where it is required if the resources are material to the issuer, as per the general securities disclosure obligation of “full, true and plain” disclosure of all material facts (see section 5.10 of the Companion Policy). If resources other than reserves are disclosed, RIs must ensure that the disclosure complies with NI 51-101, in particular sections 5.9, 5.10 and 5.16. In recent years, the disclosure of contingent resources and prospective resources has become very common.

Through review of public disclosure, the Petroleum Department observed a total of 20 RIs disclosing contingent resources or prospective resources or both during Cycle 1, as illustrated in Figure 2. During Cycle 10, this number rose to 124 issuers. While proved and probable reserves are mandated by NI 51-101 to be disclosed in the Form 51-101F1 *Statement of Reserves Data and Other Oil and Gas Information* (Form 51-101F1), the optional nature of the disclosure of resources other than reserves results in it occurring in any number of locations, including Form 51-101F1, annual information forms, corporate presentations, news releases, websites and prospectuses. Because of the challenges inherent in monitoring such a broad range of information sources, the disclosure of resources other than reserves may be underreported in Figure 2.

FIGURE 2 DISCLOSURE OF CONTINGENT RESOURCES AND PROSPECTIVE RESOURCES BY REPORTING CYCLE



2.3 Reserves Reconciliations – General

Item 4.1 of Form 51-101F1 requires disclosure of an annual reconciliation of changes in estimates of gross proved, gross probable and gross proved plus probable reserves. The reconciliation must compare reserves data at the effective date for the current financial year with the corresponding estimates at the last day of the RI’s preceding financial year. Reserves estimates within the reconciliation are accounted for under reserve change categories comprising extensions and improved recovery, technical revisions, discoveries, acquisitions, dispositions, economic factors, and production. The COGE Handbook contains descriptions of these reserves change categories and guidance on preparation of the reserves reconciliation.

In addition to providing information on the nature of activities, reserves reconciliations can provide insight into the quality of reserves estimates. In particular, the technical revisions reserves change category can help confirm if estimates meet the probability target levels described in the reserves definitions within the

COGE Handbook. Specifically, positive and negative technical revisions are generally attributed to better or poorer reservoir performance, respectively, than originally estimated. For a given entity, if reserves have been determined in accordance with the reserves definitions in the COGE Handbook, proved reserves should be adjusted positively over time, while proved plus probable reserves should remain relatively constant.

During Cycle 10, the Petroleum Department observed a number of deficiencies with respect to RIs' reserves reconciliations. Some of the more frequent deficiencies, along with the associated reserves change category, are noted below.

- **Opening balance** – Misalignment between the opening balance and the previous year's closing balance; these values should match.
- **Extensions and improved recovery** – The recording of negative volumes. Once volumes have been assigned to the extensions and improved recovery reserves change category, subsequent changes should be identified as either technical revisions or economic factors, except as noted in section 7.3.4 of volume 2 of the COGE Handbook.
- **Technical revisions** – The recording of negative technical revisions greater than 100 per cent of the opening balance. It is not possible to remove volumes of reserves in excess of the opening balance solely through a technical revision.
- **Acquisitions** – Incorrect dates used regarding the timing of reserves additions. Paragraph 7.3.3(g) of volume 2 of the COGE Handbook states "...additions are recorded at the closing date of the acquisition...", however, the correct time period to reconcile changes in the acquired reserves is actually the effective date of the RI's reserves, as per paragraph 2.7(6)(c) of the Companion Policy, which states "...the reserves estimate to be used in the reconciliation is the estimate of reserves at the effective date, not at the acquisition date, plus any production since the acquisition date. This production must be included as production in the reconciliation. If there has been a change in the reserves estimate between the acquisition date and the effective date other than that due to production, the issuer may wish to explain this as part of the reconciliation in a footnote to the reconciliation table."
- **Production** – Production volumes not aligning with volumes reported under item 6.9 of Form 51-101F1; these values should match.
- **Closing balance** – Closing balance volumes not corresponding with the volumes disclosed in response to item 2.1 of Form 51-101F1; these values should match.
- **Re-categorization of reserves** – The absence of a discussion to identify or explain the re-categorization of reserves. For example, probable reserves re-categorized as proved reserves, which can go unnoticed as a result of the proved plus probable volume remaining the same.

2.3.1 Reserves Reconciliations – Analysis and Observations

Figures 3a, 3b and 3c represent reconciliations of gross⁹ proved plus probable reserves disclosed during reporting cycle 9 (Cycle 9) and Cycle 10 for groups of issuers principally regulated by the ASC. Based on average daily gross sales volumes disclosed for Cycle 10 under item 6.9 of Form 51-101F1, issuers were ranked and then grouped as follows: seniors >100,000 barrels of oil equivalent per day; intermediates 10,000 to 100,000 barrels of oil equivalent per day; and juniors <10,000 barrels of oil equivalent per day. The top 10 seniors, 20 intermediates and 50 juniors were then selected. Within each group of selected issuers, volumes

9 As defined in CSA Staff Notice 51-324 *Revised Glossary to NI 51-101 Standards of Disclosure for Oil and Gas Activities*

disclosed in each individual reserves change category in Form 51-101F1 for each RI were then summed. The percentage change between the closing balance of Cycle 9 and the opening balance of Cycle 10 was calculated and plotted. Positive and negative changes plot to the right and left of the opening balance, respectively. While generalized, the intent is to be able to draw conclusions on the quality of reserves information disclosed by RIs of similar size.

FIGURE 3 CYCLE 10 GROSS PROVED PLUS PROBABLE RESERVES RECONCILIATIONS BY GROUP

FIGURE 3A SENIORS

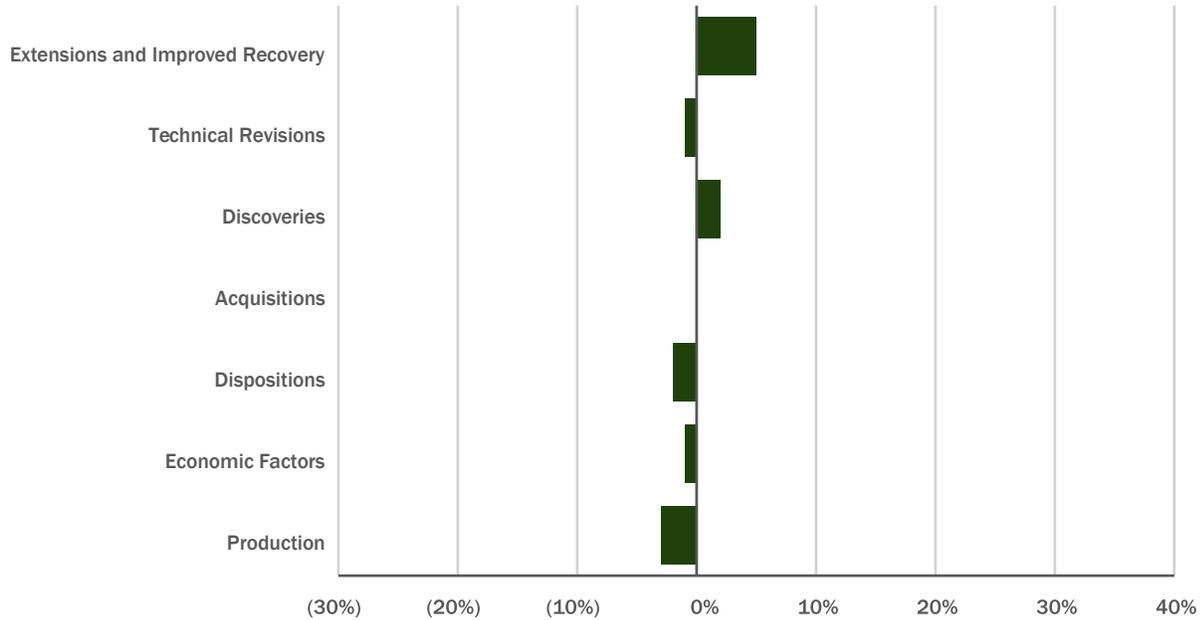


FIGURE 3B INTERMEDIATES

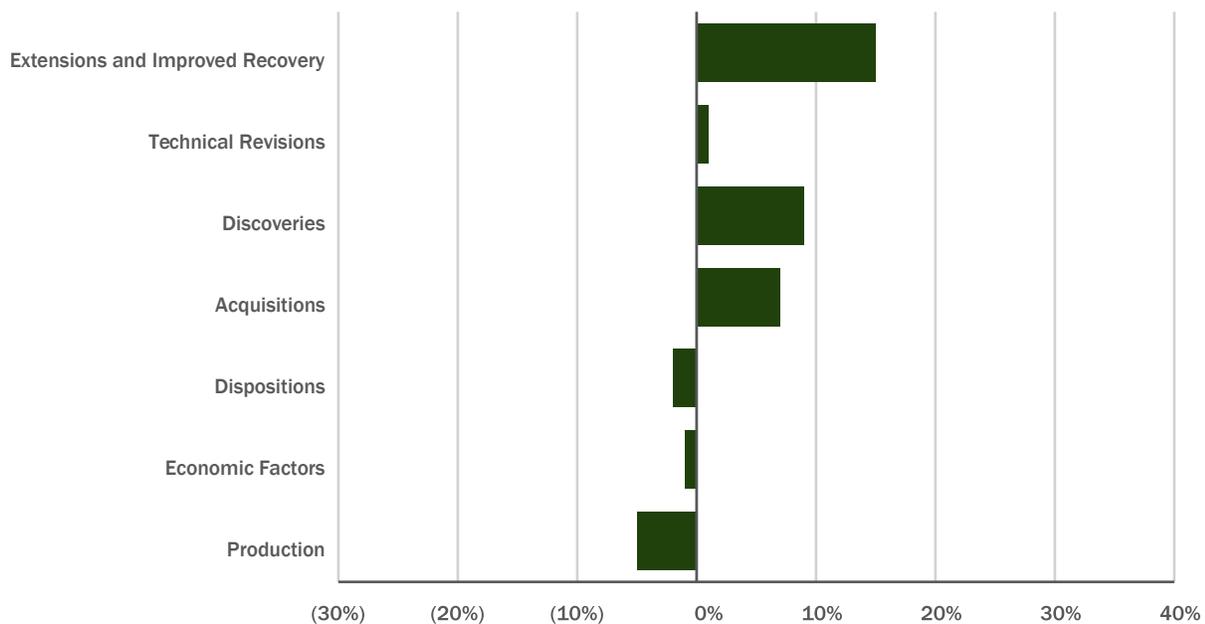
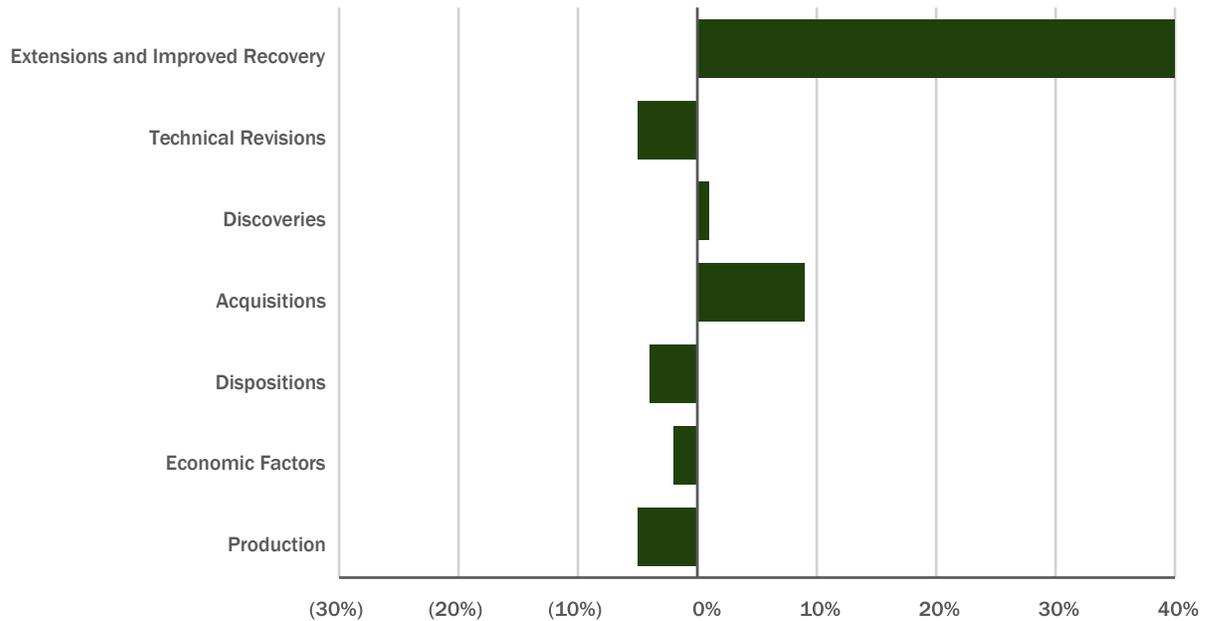


FIGURE 3C JUNIORS



Based on a review of Figure 3, the seniors exhibit the least amount of adjustment overall in gross proved plus probable reserves between cycles 9 and 10, while the juniors exhibit the most. Technical revisions between the two cycles are slightly negative for the seniors (-0.6 per cent) due to a single issuer that disclosed a negative change in probable reserves, slightly positive for the intermediates (1.0 per cent) and modestly negative for the juniors (-4.7 per cent). Breaking down the technical revisions of the 50 issuers in the juniors group: 38 disclosed a negative technical revision to probable light and medium crude oil reserves; 29 reported a negative technical revision to probable natural gas reserves; 25 reported a negative technical revision to proved light and medium crude oil reserves; and 15 issuers reported a decrease in proved natural gas reserves.

The extensions and improved recovery reserves change category for Cycle 10 shows an increase over Cycle 9 for all three groups. This increase is primarily attributed to light and medium crude oil, heavy crude oil, natural gas, NGLs and bitumen. The 40 per cent adjustment for the juniors far outpaces that for the intermediates and seniors. This is not unexpected as junior issuers frequently have a smaller number of reserves entities than either intermediate or senior issuers, and their activities are frequently directed towards identification of large resource quantities as opposed to a bias towards their development. As a result, smaller issuers typically achieve faster reserves growth than larger ones.

Changes in discoveries are small for the seniors and juniors, while for the intermediates, there is a nine per cent gain, due mainly to an increase in a single issuer's bitumen reserves. All three groups posted slight negative adjustments in economic factors that may be attributed to a reduction in natural gas price forecasts.

2.3.2 Reserves Reconciliations – Quality of Reserves Estimates

As discussed in section 2.3 of this Report, reserves reconciliations can provide insight into the quality of reserves estimates over time. The categorization of Alberta-based RIs into groups of seniors, intermediates and juniors (described in section 2.3.1) has been undertaken in this Report for the first time. While a longer-term analysis cannot presently be undertaken, some observations regarding the quality of reserves estimates can be made. The estimates for Cycle 10 appear to be of high quality for all three groups, although, as expected, the quality for individual issuers within each group varies. The modest negative technical revision for the junior RIs in Cycle 10 may suggest the need for increased care to be taken in the estimation of reserves for junior issuers. Future data will be compared to the results from Cycle 10 to determine the validity of these observations.

2.4 Type Wells

Type wells are a form of analogous information, as defined in CSA Staff Notice 51-324 *Revised Glossary to NI 51-101 Standards of Disclosure for Oil and Gas Activities* and discussed in section 5.10 of NI 51-101 and section 5.8 of the Companion Policy. Type wells are a profile of production performance over time, ideally created by averaging historical and forecast production information from select wells (the profile generated is often referred to as a “type curve”). These profiles can be used to help estimate production rates, reserves and resources other than reserves and cash flows. This information is relied upon by qualified reserves evaluators or auditors to predict production performance for wells with minimal production history and by RIs to make investment decisions regarding analogous drilling locations.

Type wells (type curves) and associated information, including recoverable volumes and economics, is increasingly being disclosed, particularly in news releases, corporate presentations and prospectuses. The ASC is monitoring this practice and has noted a number of common deficiencies.

- **Information not sourced** – Many RIs disclose type well information that is not properly sourced, which can potentially mislead readers into concluding that information has been prepared by the RI’s independent qualified reserves evaluator or auditor when it may in fact have been prepared by the RI. Properly distinguishing the source of type well information is critical.
- **Poor methodology** – Type well information disclosed by RIs sometimes includes only the best wells and excludes dry holes and poor performing wells, while wells with dissimilar reservoir parameters or dissimilar completion procedures are sometimes included; concerns about methodology are often compounded by an absence of a methodology discussion. As section 5.8 of the Companion Policy states: “It is important to present a factual and balanced view of the information being provided.”
- **Misclassified or unclassified estimates** – Disclosed estimates of reserves and resources other than reserves associated with type wells are often classified without regard for the applicable terminology and categories set out in the COGE Handbook as per section 5.3 of NI 51-101, which states that “Reserves or resources other than reserves must be disclosed using the applicable terminology and categories set out in the COGE Handbook and must be classified in the most specific category of reserves or resources other than reserves in which the reserves or resources other than reserves can be classified.” Unacceptable terminology applied to recoverable volumes observed by the ASC includes: “EUR” (estimated ultimate recovery); “recoverable resources”; “recoverable reserves”; “reserves” (not specifying proved, probable or possible); “contingent resources” (not specifying low, best or high estimates); and “prospective resources” (not specifying low, best or high estimates). In other instances, estimates are provided that lack any classification and simply comprise a volume and value.

Reporting issuers are reminded of the guidance in section 5.8 of the Companion Policy regarding analogous information and in item 2(a) of CSA Staff Notice 51-327 *Revised Guidance on Oil and Gas Disclosure* and the requirements of section 5.10 of NI 51-101.

2.5 Petroleum Losses in Foreign Jurisdictions

In the present context, “petroleum losses” refers to the theft and trade of produced petroleum acquired from field operations, pipelines, export terminals and commercial shipping vessels. These losses may occur anywhere petroleum is produced or traded. The Niger River Delta of Nigeria is a current focal point for petroleum losses. In August 2012, the Petroleum Revenue Special Task Force, commissioned by the Honourable Minister of Petroleum Resources of Nigeria, estimated daily losses of six to 30 per cent of production. This equates to 114,000 to 570,000 barrels per day of oil in February 2014. As of early 2014, 16 RIs in Alberta disclosed Nigerian interests, with four reporting production from these interests. Only two of these four disclosed petroleum losses due to theft as a risk.

Use of the term “petroleum losses” in the absence of additional description and disclosure is not informative and may be potentially misleading. For instance, the term can be used to describe losses attributed to any number of both legal and illegal means in isolation or combination. The term “bunkering” is sometimes used and is also problematic, as it is frequently used to describe both petroleum theft and the legal supply of petroleum products to ships.

The ASC anticipates the potential for additional RIs in Alberta to experience petroleum losses due to theft in foreign jurisdictions. The ASC’s Petroleum Department is reviewing the issue. Current disclosure from RIs regarding these losses may not be adequate.

3. Amendments to NI 51-101

3.1 Background

On October 17, 2013, the CSA published the Proposed Amendments¹⁰ to NI 51-101, its related forms and the Companion Policy, and initiated a 90 day comment period. This was undertaken in response to both the CSA's observations of RI disclosure and industry feedback. The Final Amendments were published on December 4, 2014 with an effective date of July 1, 2015. The Amendments promote improved disclosure of resources other than reserves, provide increased flexibility for oil and gas issuers that operate and report in different jurisdictions or recover product types not previously recognized by NI 51-101, and align NI 51-101 with the recently updated COGE Handbook (comprising the Bitumen Guidelines and the ROTR Guidelines). Although the Amendments do not take effect immediately, as per NI 51-101, RIs are required to immediately follow the guidance in the COGE Handbook, which is amended from time to time.

The Proposed Amendments included:

- in certain circumstances and subject to disclosure requirements, disclosure prepared under an alternative resources evaluation system is permitted;
- inclusion and refinement of product type definitions in NI 51-101;
- additional requirements regarding the disclosure of contingent and prospective resources;
- introduction of a principle-based approach to the disclosure of oil and gas metrics;
- clarification of the point at which sales of product types and associated by-products should be disclosed;
- definition of and requirements related to the disclosure of abandonment and reclamation costs;
- removal of the requirement to match the presentation of reserves not directly held by the RI in the statement prepared in accordance with Form 51-101F1 to the presentation of the assets in the financial statements;
- removal of the requirement to obtain independent qualified reserves evaluator consent before disclosing results from the annual evaluation outside of the required annual filings;
- revision of the date at which the independent qualified reserves evaluator takes responsibility for information related to the reserves evaluation; and
- clarification of required disclosure when an issuer has no reserves.

Thirteen letters were received during the comment period that ended January 15, 2014. The letters were from six large RIs, three independent qualified reserves evaluators or auditors, one senior oil sands RI, one law firm, one individual and one professional organization. Additional verbal comments were received both during and following the comment period from large RIs, independent qualified reserves evaluators or auditors and the ASC's Petroleum Advisory Committee. The comment letters are posted on the ASC's website at www.albertasecurities.com. The CSA extends its appreciation to all those who contributed.

¹⁰ CSA Notice and Request for Comments – Proposed Amendments to NI 51-101 *Standards of Disclosure for Oil and Gas Activities* and *Proposed Changes to Companion Policy 51-101CP Standards of Disclosure for Oil and Gas Activities*, published October 17, 2013

The comments received were generally supportive of the Proposed Amendments, although the amendment concerning additional requirements regarding the disclosure of contingent and prospective resources was the most contentious. The comments have been carefully considered by the CSA and the results are reflected in the Amendments.

Subsections 3.2, 3.3 and 3.4 provide additional information relating to several of the Amendments, including requirements for estimation and disclosure of contingent resources and prospective resources and clarification of the point at which reporting of resources and sales of product types and associated by-products should occur. This information is included in response to the feedback received during the comment period and provides further support and context for the Amendments. This is followed by a brief summary of information concerning several other Amendments.

3.2 Contingent Resources and Prospective Resources – Risked Net Present Value

The primary method of evaluating oil and gas properties is discounted cash flow analysis. The net present values (NPVs) of discounted cash flows are used to both establish values of oil and gas assets and rank investment opportunities. Discounted cash flow analysis is discussed in detail in volume 1 of the COGE Handbook. As stated in section 8.2 of the COGE Handbook, “By definition, oil and gas volumes can be classified as reserves only if they are economically viable to produce. Economic viability is a subjective concept, but in many cases it is satisfied when the net present value is positive at a selected discount rate.” On an economic basis, NPVs are used to help classify and categorize reserves and resources other than reserves and sub-classify resources such as contingent resources.

There is uncertainty associated with the input parameters of a discounted cash flow analysis, including resources estimates, production rates, product prices, royalties and operating and capital costs. Risk analysis is incorporated into the evaluation to try to address these uncertainties. Risking methods commonly used by industry range from simple approaches, for instance the use of higher discount rates for future cash flows/future net revenue (however, as per section 8.2 of volume 1 of the COGE Handbook, this approach is not recommended), to decision tree analysis using expected value theory, to more sophisticated methods such as probabilistic analysis using Monte Carlo simulation.

The Society of Petroleum Engineers Petroleum Resources Management System (SPE-PRMS) defines risk as “the probability of loss or failure.” As “risk” is generally associated with a negative outcome, the term “chance” is preferred for general usage to describe the probability of a discrete event occurring. Quantitatively speaking, chance = 1-risk. SPE-PRMS defines “chance of commerciality” as the chance that a project will be developed and reach commercial producing status.

The COGE Handbook defines contingent resources as “resources not currently considered commercially recoverable due to one or more contingencies.” Contingent resources are sub-classified based on chance of commerciality and project maturity. A project sub-classified as “development pending” has the highest chance of commerciality. Once commerciality is established, contingent resources can be reclassified into the appropriate corresponding reserves categories.

As described in the recently published ROTR Guidelines, prospective resources have both a chance of discovery and a chance of development. They are sub-classified in accordance with the level of uncertainty associated with their recoverable estimates, assuming their discovery and development and may be sub-classified based on project maturity. As stated in the ROTR Guidelines, “Because an evaluator with access to all available data for a prospect should have an informed opinion of the chance of discovery, it can be

potentially misleading to disclose unrisken estimates of prospective resources and leave the risk to the investor.”

The Amendments provide clearer guidance and a framework regarding the disclosure of contingent resources data and prospective resources data in Form 51-101F1. For instance, since contingent resources and prospective resources are subject to risks that result in less than 100 per cent chance of commerciality, the qualified reserves evaluator or auditor will need to determine and address those risks if contingent resources and prospective resources are included in the Form 51-101F1. The disclosure is required to be accompanied by the risk factors themselves and an explanation regarding how the risks have been determined. In addition, the disclosure of contingent resources and prospective resources is required to occur in an appendix to the Form 51-101F1.

Expected Value Theory (EVT) is one of the more common methods used by industry to quantify risk volumes and values of resources. The expected value is the sum of all the possible outcomes of a project, such as volumes and values of the resources, multiplied by their respective estimated probabilities of occurrence using a risk methodology determined by the RI. EVT is simply a decision tool; the expected value is not the actual value of the contingent resources or prospective resources, but an average of the outcomes weighted by probabilities of the individual outcomes. If the RI has a large number of similar projects and they are executed many times, the actual value obtained may approach the expected value.

If the expected value is in monetary terms, the calculated expected value is called Expected Monetary Value (EMV). It is one method that can be used to estimate a risk net present value of future net revenue. One occurrence for a single project is unlikely to achieve the calculated EMV. In theory, by always choosing projects with the greatest positive EMV, the RI may achieve better results than may be achieved by making random decisions. As discussed above, there are many methods that can be used to determine risk and a particular method is not prescribed.

Contingent resources in the “development pending project maturity sub-class” have the highest chance of development and commerciality of all the project maturity sub-classes of contingent resources. Because there is additional uncertainty with the other project maturity sub-classes of contingent resources and prospective resources, disclosure of the risk NPV of prospective resources and contingent resources in any project maturity sub-class other than “development pending” in the Form 51-101F1 must be accompanied by a detailed explanation regarding the chance of commerciality.

3.3 Marketability of Resources and Production

The Amendments to NI 51-101 clarify the concept of marketability with respect to the reporting of resources (including reserves and resources other than reserves) and sales of product types and associated by-products. Section 5.4 of NI 51-101 requires the RI to report at the first point of sale of a particular product type, unless that point is not relevant, in which case the RI may disclose resources or sales of product types or associated by-products with respect to an alternate reference point if, to a reasonable person, the resources, product types or associated by-products would be marketable at the alternate reference point. If reporting is made with respect to an alternate reference point, the reporting issuer must state this fact, disclose the location of this alternate reference point and explain the rationale for not reporting at the first point of sale. Section 5.5 of NI 51-101 has been amended to require that disclosure of natural gas by-products, including NGLs and sulphur, be made only for volumes that have been or are to be recovered prior to the first point of sale, or alternate reference point, as applicable.

Section 7.2.2 of volume 1 of the COGE Handbook states that “Oil, gas, and by-product reserves must be reported on a marketable basis. This refers to the volume of reserves that changes ownership for the first time, either at the wellhead or downstream at a processing facility. For oil production the change in ownership occurs at the custody transfer point to pipeline, downstream of the operator’s oil battery, or at a terminal to which oil is trucked from a well or pool battery. Gas is usually sold downstream of a producer’s processing plant, the point referred to as the “field gate.” Occasionally, it is sold at the wellhead or downstream from the plant at an interconnection with a major transmission line.”

Resource quantities are estimated in terms of the “sales products” measured in their condition as accepted at the custody transfer (or reference) point. The reference point is the same for both the measurement of reported sales quantities and for the accounting treatment of sales revenues. This ensures that sales quantities are stated according to their delivery specifications at a defined price. Generally, to comply with NI 51-101 requirements, disclosure should be consistent with financial statements.

Based on section 7.2.2 of volume 1 of the COGE Handbook and sections 5.4 and 5.5 of NI 51-101, it stands to reason that if custody or title of wet gas (raw gas) is transferred at the inlet to the gas processing facility (which is before the wet gas is processed into its component dry gas and natural gas liquid by-products) resources can only be assigned to the wet gas and not to its component dry gas and natural gas liquid by-products. If custody or title is transferred at the plant outlet, which is after processing of the wet gas into dry gas and natural gas liquid by-products, then the residue gas volumes and natural gas liquid by-products can be assigned as resources.

With the increasing industry focus on NGLs, large quantities of NGLs and NGLs-rich natural gas reserves and resources other than reserves have been assigned in recent years. In situations where custody or title to natural gas is transferred at the inlet to the gas processing facility, the RIs receive an economic benefit with respect to the entrained NGLs. While these RIs may desire to have the component dry gas and natural gas liquid by-products assigned as reserves and resources other than reserves, this is not supported by the current legislation.

3.4 Other Amendments

- **Alternative Resources Evaluation Standard** – Section 5.18 of NI 51-101 has been amended to allow for supplementary public disclosure under alternate regimes for Canadian RIs subject to other reserves disclosure regimes, for instance that of the United States Securities and Exchange Commission.
- **Product Types and Production Groups** – The concept of production groups has been eliminated, while product type definitions have been imported from the COGE Handbook and refined. This will provide greater emphasis regarding both hydrocarbon sources and recovery processes and their associated costs and risks.
- **Oil and Gas Metrics** – Section 5.14 of NI 51-101 has been amended to include principle-based requirements to describe the standard, methodology and meaning of a publicly disclosed oil and gas metric and provide a cautionary statement regarding the reliability of the metric. If there is no standard, a RI must describe the parameters used in calculating the metric and provide a cautionary statement.
- **Abandonment and Reclamation Costs** – The definition of abandonment and reclamation costs for the purposes of oil and gas disclosure has been modified and the disclosure of abandonment and reclamation costs in future net revenue and significant factors and uncertainties is now required.

- **No Oil and Gas Activities to Report** – New Form 51-101F5 *Notice of Ceasing to Engage in Oil and Gas Activities* has been developed for use when issuers cease to be engaged, either directly or indirectly, in oil and gas activities.

4. Recent Updates to the COGE Handbook

NI 51-101 refers to the COGE Handbook as the technical standard for the preparation of oil and gas information for disclosure, and has been used for this purpose since NI 51-101 was implemented in 2003. The COGE Handbook is maintained by the SPEE, Calgary Chapter and consists of:

- Volume 1 – Reserves Definitions and Evaluation Practices and Procedures;
- Volume 2 – Detailed Guidelines for Estimation and Classification of Oil and Gas Resources and Reserves; and
- Volume 3 – CBM Reserves and Resources/International Properties/Bitumen and SAGD Reserves Resources.

The COGE Handbook is updated from time to time. Recent updates include:

- Detailed guidelines for estimation and classification of bitumen resources (Bitumen Guidelines), effective April 1, 2014; and
- Guidelines for estimation and classification of resources other than reserves (ROTR Guidelines), effective July 17, 2014.

Reserves have been the principal focus of previous editions of the COGE Handbook. These guidelines are a response to the changes that have occurred in the oil and gas industry in recent years. Specifically, the industry has been increasingly focused on the application of both new and improved technologies, such as horizontal drilling, massive hydraulic fracturing stimulations and enhanced oil recovery, including steam assisted gravity drainage (SAGD) and its many variants. This has in turn encouraged the exploitation of previously technologically inaccessible reservoirs, such as low permeability shales and siltstones, and accelerated and improved exploitation from developed ones. The Amendments to NI 51-101 have been undertaken in part to align NI 51-101, its related forms and the Companion Policy, with the recent changes to the COGE Handbook.

Sections 4.1 and 4.2 highlight key information contained within the Bitumen Guidelines and ROTR Guidelines.

4.1 Bitumen Guidelines

Key topics addressed include:

- Evaluation of bitumen resources and reserves;
- Classification of bitumen resources;
- Recovery methods, including in situ and mining;
- Fiscal regimes;
- Project management and costing;
- Analogs;
 - Some key considerations concerning the use of analogs include:
 - Analogs should be as specific as possible and directly relevant to the assessment of recoverability from the reservoir of interest. The subject reservoir should have a similar geological setting and ideally a similar operational strategy as the analogy;
 - Parameters of the subject reservoir should be equal to or better than the analogy. If the quality is poorer, expectations for the subject reservoir should be reduced;
 - All technical attributes may not be comparable, including the specific recovery process. The evaluator may need to compensate or infer the influence that differences may have on performance; and
 - The lack of a reasonable analog should significantly increase the range of expected outcomes.
- Pilot projects;
 - Some key considerations concerning pilot projects include:
 - Pilot projects often operate for a limited time, are placed in optimal reservoirs, have facility limitations and may have well completions that won't ultimately be used for a commercial project; and
 - Caution should be exercised when results from a pilot project are used as an analogy for a larger project.

4.2 ROTR Guidelines

Key topics addressed include:

- Project scenarios
 - The assignment of contingent resources and prospective resources requires a project scenario;
 - The project definition level should be consistent with the project maturity sub-class;

FIGURE 4 PROJECT MATURITY SUB-CLASSES

TOTAL PETROLEUM INITIALLY-IN-PLACE (PIIP)	DISCOVERED PIIP	COMMERCIAL	PRODUCTION	PROJECT MATURITY Sub-Classes	Increasing Chance of Commerciality		
			RESERVES			On Production	
						Approved for Development	
		Justified for Development					
		SUB-COMMERCIAL	CONTINGENT RESOURCES			Development Pending	
						Development on Hold	
	Development Unclassified						
	Development not Viable						
	UNRECOVERABLE						
	UNDISCOVERED PIIP	PROSPECTIVE RESOURCES	Prospect				
Lead							
Play							
UNRECOVERABLE							

Modified from the COGE Handbook.

- “Development pending” project maturity sub-class of contingent resources;
- A project sub-classified as “development pending” has the highest chance of commerciality. Classification in this sub-class requires:
 - There must be no technical issues (technical contingencies) that prevent the project from being commercially viable;
 - Technical contingencies must be resolved through the acquisition of additional technical data regarding the reservoir or recovery process to allow the commercial application of a recovery process technology to a specific reservoir; and
 - Efforts to remove the outstanding non-technical contingencies can be expected to be resolved positively within a reasonable timeframe, permitting reclassification of the contingent resources directly into the corresponding reserves confidence categories. Low, best and high estimates of contingent resources become proved, probable and possible reserves, respectively. Non-technical contingencies include corporate commitment, economics, legal, environment, political or regulatory matters, or the lack of markets.
- Extrapolation

- Extrapolation of reservoir presence or productivity beyond the immediate vicinity of a control point should be limited in the absence of clear technical supporting evidence that takes into account the presence of the geological unit and the presence and recoverability of the petroleum;
- A continuous deposit may be mapped over a relatively large area on the basis of a limited number of wells, but test data or productivity will generally be extrapolated over a much smaller area; and
- In the absence of support data, classification of petroleum initially in-place as discovered resources should be limited to the immediate vicinity of a wellbore. Ideal support data is test or production information.
- **Analogs**
 - Target reservoirs must perform in a similar or better manner than the analog using the same recovery process; and
 - Analogs cannot be used to establish the presence of productive reservoir beyond the immediate vicinity of a control point.
- **Recovery technologies**
 - Experimental technology – Technology that is being field tested to determine the technical viability of applying it to recover currently unrecoverable discovered petroleum initially in-place in a subject reservoir; reserves, contingent resources, or prospective resources cannot be assigned;
 - Technology under development – Technology that is technically feasible and being field tested to determine economic viability in the subject reservoir; contingent resources may be assigned if the results satisfy the requirements; and
 - Established technology – Technology that has been proven successful in commercial applications.

5. Petroleum Advisory Committee

The Petroleum Advisory Committee (PAC or Committee) is an important source of oil and gas information and advice for the ASC. The Committee is comprised of volunteer members (PAC Members) drawn from the oil and gas industry and appointed by the ASC to three-year terms. Committee meetings are normally held four times per year and are complemented with observers consisting of select staff and executives from the ASC and invited outside participants. The mandate of the PAC is to:

- Review and provide advice and opinions on issues, trends and current developments relating to evaluations of oil and gas reserves and resources other than reserves;
- Provide comment on current and proposed Alberta securities laws and regulatory policies in this area; and
- Provide advice to ASC staff on an informal basis.

Topics discussed during the last year include:

- Proposed Amendments to NI 51-101;
- Updates to the COGE Handbook: Bitumen Guidelines and ROTR Guidelines;
- Use of the term “commerciality” in a manner contrary to its definition in the COGE Handbook;
- The booking of natural gas liquids and the requirement for ownership to be established;
- Payments made to governments by Canadian extractive companies;
- Concession expiries and the booking of reserves; and
- Petroleum losses in foreign jurisdictions.

The ASC thanks PAC Members for their time and contributions over the past year. The ASC also expresses its gratitude to PAC Members who retired following completion of their terms.

CYCLE 11 MEMBERS OF THE PAC

David P. Carey, P.Eng., MBA
ARC Resources Ltd.

Keith McCandlish, P.Geol., P.Geo.
DMT Geosciences Ltd.

Jonathan Fleming, B.Comm., MBA
DeeThree Exploration Ltd.

Ian McDonald, P.Eng.
Nexen Energy ULC

Chris Fong, P.Eng.
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Rob Morgan, P.Eng.
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6. Contact Information

The ASC's Petroleum Department hosts annual NI 51-101 information sessions, presents at conferences, maintains the PAC and continuously seeks new communication opportunities.

Phillip Chan retired as Chief Petroleum Officer and Manager in October 2014. The ASC thanks Phil for his contributions.

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