What is the Canadian Oil and Gas Evaluation (COGE) Handbook?

Brief History of the COGE Handbook
  - Authors of COGEH
  - Timeline for COGEH publications

Why Update the COGE Handbook?

Revised Structure
  - Seven Chapters

Selected Topics for Discussion

Relationship with PRMS
ABOUT THE COGE HANDBOOK

• The COGE Handbook has been prepared by the Calgary Chapter of the Society of Petroleum Evaluation Engineers (SPEE Calgary)

• COGEH provides good practice standards and guidelines to be used in oil and gas Reserves and Resource evaluations

• SPEE Calgary expects all Canadian companies, whether public or private, will use the standards and guidelines set out in the Handbook
The Society of Petroleum Evaluation Engineers (SPEE) is dedicated to the advancement of the profession of Petroleum Evaluation Engineering by demonstrating the highest standard of ethics, promoting continuing education of our membership and by education of the public in the area of oil and gas reserves definitions, reserve evaluations, and fair market value.

The Calgary Chapter of the SPEE is responsible for writing and maintaining the Canadian Oil and Gas Evaluation (COGE) Handbook. Website: www.speecanada.org
WHY UPDATE THE COGE HANDBOOK

• Consolidate the old three volumes into ONE
  – Remove inconsistencies, repetition and outdated information
• Incorporate advances in unconventional resources
• Align with current industry best practices
• Modernize the distribution of COGEH
  – Previously only available in hard copy
  – New version is digital, searchable and available by subscription on the SPEE Canada website
• Evergreen - Simplify future updates
  – SPEE can edit, revise or add sections without publishing new volumes
COGE HANDBOOK STRUCTURE

• Chapter 1 - Introduction and Definitions
• Chapter 2 - Estimation of Reserves and Resources
• Chapter 3 - Economic Evaluation of Reserves and Resources
• Chapter 4 - Financial Analysis and Benchmarking Practices
• Chapter 5 - Purpose of Evaluations
• Chapter 6 - Coalbed Methane Reserves and Resources
• Chapter 7 - Bitumen Reserves and Resources
• Appendices
TOPICS FOR DISCUSSION

• COGEH vs. Disclosure
• Projects
• Development timing
• Evaluation of low permeability reservoirs
• Abandonment, Decommissioning & Reclamation
• Operating Costs - Active & Inactive Assets
• Maintenance Capital
• Clarification of Other Items
• Differences with PRMS
COGEH VS DISCLOSURE

• COGEH lays out the guidelines that are applicable to all oil and gas assessments
• COGEH defines many terms of use

• Canadian Securities Administrators (CSA) sets disclosure standards for publicly traded O&G companies in National Instrument 51-101 (NI 51-101).
• COGEH is then referenced by NI51-101
• NI51-101 specifies what is required to be disclosed and when

“If a reporting issuer makes disclosure of reserves … the reporting issuer must ensure that the disclosure … have been prepared or audited in accordance with the COGE Handbook”
PROJECTS (1.5)

• Definition: “A defined activity or set of activities for the discovery or recovery of oil and gas and associated by-products.”
  – A project provides the basis for the assessment and classification of Resources

• Types of Projects
  – Recovery Projects
    • Drilling, Stimulation, Enhanced Recovery, Artificial Lift, Mining
  – Pipelines, Gathering Systems, Compression
  – Processing Facilities
  – Offshore Platforms
PROJECT DESCRIPTION LEVELS (1.5.3)

• Level I (Early Stage)
  – Conceptual development plan suitable for Prospective Resources or unclarified Contingent Resources

• Level II (Intermediate Stage)
  – Development plan is better defined than conceptual and may be suitable for assignment of Contingent Resources of any sub-class

• Level III (Advanced Stage)
  – Development plan is sufficiently detailed to provide for final investment decision and suitable for the assignment of reserves
For Undeveloped Reserves, development should normally proceed within 5 years*

For large projects, approvals and final investment decision must be made or expected and capital expenditures should commence within:

- 3 years for Proved Undeveloped Reserves
- 5 years for Probable Undeveloped Reserves
DEVELOPMENT TIMING (1.4.7.2.1.8)

• Common Situations
  
  – Ongoing Resource Play Development Drilling Schedule:
    • maximum 5 years for Proved Undeveloped Reserves
    • maximum 10 years for Probable Undeveloped Reserves*

• * These recommended maximums are for drilling programs which have been underway for a few years, with a large inventory of reserves locations with demonstrated robust economic returns.
• Common Situations (cont.)

– Gas Processing Facilities with construction underway and completion expected in 2 years (new facility or expansion)
  • Development drilling for maximum 5 years after completion of facility for Proved Undeveloped Reserves
  • Development drilling for maximum 10 years from evaluation effective date for Probable Undeveloped Reserves

– In-Situ Projects
  • Drilling well-pairs may be scheduled for the time period required to recover the assigned Reserves
  • Drilling limited to facility design life or extended with maintenance capital to a maximum 50 years
Common Situations (cont.)

- **Bitumen Mining Projects**
  - Mining limited to facility design life or extended with maintenance capital to a maximum 50 years

- **Offshore Projects**
  - Drilling may be scheduled for the time period required to recover the assigned Reserves within the approved development project
  - Drilling limited to facility design life or extended with maintenance capital to a maximum 50 years

- **Other Projects (example LNG or GTL)**
  - Appropriate timing with the foregoing as illustrative examples
RISK AND UNCERTAINTY (1.6)

- General concepts behind the evaluation, classification and categorization of Resource estimates.
- The concepts of risk and uncertainty are fundamental to understanding Resource classification and categorization:
  - Risk refers to a likelihood of loss and is described by the Resource Class
  - Uncertainty is used to describe the range of possible outcomes of a Resource estimate and is described by the Resource Categories: Low, Best, and High (1P, 2P and 3P)
SECTION 2 ESTIMATION OF RESERVES AND RESOURCES

• New improvements to Section 2 include:
  – Integration of various methods over time (2.1.1)
  – Data acquisition over time (2.3.1)
  – Various physical tests used in reserves determination: core, logs, flow tests etc.

<table>
<thead>
<tr>
<th>Exploration</th>
<th>Appraisal and Development</th>
<th>Development</th>
<th>Blowdown</th>
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<tr>
<td>Geophysical</td>
<td>Seismic (2D, 3D) Averaging/Electromagnetic mapping</td>
<td>Seismic (2D, 4D) Vertical Seismic Profiling (VSP)</td>
<td>Seismic (4D) Vertical Seismic Profiling (VSP)</td>
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<td>Geological</td>
<td>Log Data: Static Core (Whole, Sidewall), Solids/Cuttings Testing</td>
<td>Log Data: Static Core (Whole, Sidewall), Solids/Cuttings Testing</td>
<td>Log Data: Static Core (Whole, Sidewall), Solids/Cuttings Testing</td>
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</tbody>
</table>

Table 2-1 Data Requirements Over Pool/Reservoir Life
• Prior versions of COGEH focused on conventional oil and gas accumulations

• Conventional reservoir tools are still discussed:
  – Findings during F&BU tests very indicative of reservoir conditions
  – Build-up pressures are reliable and a key tool
  – Log and core analysis was a strong indicator of reservoir capability (poro-perm relationships etc.)
EVALUATION OF LOW PERMEABILITY RESERVOIRS (CHAPTER 2)

• Conventional reservoir tools are still discussed (cont.):
  – Decline analysis was concentrated on medium to high permeability reservoirs using Arps
    • Characterized by short transient periods and substantially more time in the PSS and boundary dominated flow periods
    • Guidance was provided on multi-well pools with expected interaction between subsequent wells
New guidance was written in the context of best practices in the evaluation of tight and unconventional reservoirs.

Production analysis remains a key tool:
- The process of completing a HMSF well creates flow paths leading to transient linear/bi-linear flow early time.
- These wells spend many months and years in transient flow periods and proportionately less time in BDF.
- This decline behaviour is expected to be dynamic over time.
- This necessitates the proper identification of flow regimes prior to decline analysis.
New COGEH introduces Alternative Decline Methods

Discusses the widely used solution to model HMSF decline behaviour using the Modified Hyperbolic Decline (MHD)

- MHD uses a staged hyperbolic decline as well moves through flow regimes:
  - Starts with a high transient b factor, through a moderate stabilized b factor, and ultimately a low b factor of near zero.
EVALUATION OF LOW PERMEABILITY RESERVOIRS (CHAPTER 2)

- Description of Production Analysis Methods (2.6)
- Now provides a table for Recommended Application of Decline Techniques (2.6.1.3)

<table>
<thead>
<tr>
<th></th>
<th>Arps (orig.)</th>
<th>Arps (mod.)</th>
<th>Stretched exponential (orig.)</th>
<th>Stretched exponential (mod.)</th>
<th>Linear flow (orig.)</th>
<th>Linear flow (mod.)</th>
<th>Duong (orig.)</th>
<th>Duong (mod.)</th>
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<td>Reasonable forecasts for low permeability reservoirs?</td>
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<td>maybe</td>
<td>maybe</td>
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<tr>
<td>Valid for transient flow?</td>
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<td>no</td>
<td>yes</td>
<td>yes</td>
<td>yes</td>
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<td>yes</td>
<td></td>
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<tr>
<td>Valid for BDF?</td>
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<td>Need to change parameters with longer history?</td>
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<td>yes</td>
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<td>yes</td>
<td>yes</td>
<td>yes</td>
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<td></td>
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<tr>
<td>Good with limited data (&lt; 1 year)?</td>
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<td>no</td>
<td>no</td>
<td>no</td>
<td>no</td>
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<td>no</td>
<td></td>
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<tr>
<td>Easy to use, combine with economics Software?</td>
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<td>yes</td>
<td>somewhat</td>
<td></td>
<td></td>
<td></td>
<td></td>
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Table 2-7 Decline Methodology Strengths and Limitations

<table>
<thead>
<tr>
<th>Decline Model</th>
<th>Major Strength</th>
<th>Major Limitation</th>
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<tbody>
<tr>
<td>Arps (original)</td>
<td>Easy to use, couple with economics software</td>
<td>Requires BDF, constant BHP</td>
</tr>
<tr>
<td>Arps (modified)</td>
<td>Easy to use, couple with economics software, valid in BDF</td>
<td>Early BDF, late exponential decline required</td>
</tr>
<tr>
<td>Stretched exponential</td>
<td>Transient flow model</td>
<td>Not accurate in BDF, tends to be conservative in most cases</td>
</tr>
<tr>
<td>Linear flow</td>
<td>Correct physics for many fractured wells</td>
<td>Inappropriate for BDF, optimistic</td>
</tr>
<tr>
<td>Duong</td>
<td>Correct physics for many fractured wells (essentially linear flow)</td>
<td>Inappropriate for BDF, optimistic</td>
</tr>
<tr>
<td>Duong (modified)</td>
<td>Correct physics during transient and BDF</td>
<td>Not available in commercial software</td>
</tr>
</tbody>
</table>
EVALUATION OF LOW PERMEABILITY RESERVOIRS (CHAPTER 2)

- Introduces Type Wells and Type Curves (2.7)
  - Type wells: performance of group of wells selected as analogs
  - Type curves: future normalized forecast for planned development
- Requires proper conditioning of the data:
  - Normalize data
  - Survivor Bias
- You will typically be looking at a large number of individual well results, and need to consider the statistics of the sample:
  - Forecast the Average
    - Average all the history for a sample into a partial type well, then create a forecast of the average
  - Average the Forecasts (preferred)
    - Forecast all the wells in the sample and create a set of prescriptive statistics for of all the history and forecasts
NORMALIZING AND SCALING FOR KEY ATTRIBUTES

• When working with large datasets, it is important to recognize there are many variables or “attributes” of a well
• Attributes which may cause performance to differ from other wells include but are not limited to:
  – vintage, operator, length and spacing, reservoir quality, cardinality, geographic location, frac fluid type, volume and rate, proppant type and tonnage, number of stages, distance to offset producers, and age of the well relative to offsets.
• It is very important when assessing type wells and ultimately future performance expectations for an area, these types of attributes are investigated.
NORMALIZING AND SCALING FOR KEY ATTRIBUTES

• Example attribute(s):
  – Hz well length and Well vintage
  – Note both may have impact on production performance
When reviewing type wells, avoid analysing only the mean or average of the data. This limits the information used in further analysis.
• Probit or log normal models can help quantify the uncertainty.

• Many well attributes and resulting performance metrics must be investigated:
  – IP90, Sand Tonnage, EUR, Pump Rate and Fluid etc.
NORMALIZING AND SCALING FOR KEY ATTRIBUTES

All wells are not created equal!
CHOOSING APPROPRIATE TYPE CURVES (2.7.4 AND 2.7.5)

- Create Correlations and Crossplots to understand the results
- Create Maps which highlight performance bands or tiers

Figure 2-42 Performance “Bands” Example – Rank Mapping
CHOOSING APPROPRIATE TYPE CURVES (2.7.4 AND 2.7.5)

• Once the technical type well analysis has been completed, it is likely the evaluator has a good understanding of the Best Estimate (2P, mean or average outcome) for a given area or sub-area.

• The technical uncertainty in the area (geology and engineering) and the number of undeveloped locations to be booked will impact the range of 1P (P90) and 3P (P10) type wells.
UNDEVELOPED RESERVES RELATED TO FUTURE DRILLING (2.10)

• The new COGEH material adds to the concepts established for conventional reservoirs and establishes best practices for undeveloped assignments in unconventionals.

• All relevant factors must be considered when booking undeveloped drilling locations, including:
  – geological control, petrophysical data, reservoir quality, well performance, drainage area, underlying water, overlying gas, drive mechanism, addition of compression, artificial lift, potential for infill drilling, and potential for enhanced recovery.

• Analogous pools can provide valuable information for analysing the impact of such factors on Reserves estimation and classification.

• It is recommended volumetric Reserves estimation in multi-well pools be based on a single net pay isopach map representing the Best estimation of the extent and configuration of the pool.
• Discussion of the drill spacing unit (DSU)
  – Not the traditional regulatory designated area or unit
• Instead, we use DSU as the drilling convention based on the optimum or planned spacing required to drain Reserves from a pool:
  – This spacing reflects good engineering practice, as well as the results of reservoir delineation and modeling studies, and is typically documented in an approved field development plan.
  – This DSU spacing must be considered inside of a 3D volume, not simply planar area
  – This generally described DSU can be considered a function of the density to which a subject reservoir is to be developed and the development strategy and incremental capital commitment associated with the reservoir.
  – In such cases, Reserves are classified based on assessment of the confidence levels applicable to the various parameters assigned in the developed and undeveloped portions of the pool.
UNDEVELOPED RESERVES RELATED TO FUTURE DRILLING (2.10)

- Discussion of the drill spacing unit (DSU)
  - Not the traditional regulatory designated area or unit
- Instead, we use DSU as the drilling convention based on the optimum or planned spacing required to drain Reserves from a pool:

**Figure 2-49** EUR per well, reservoir recovery factor and NPV as a function of development spacing.
DELINEATION WELL ANALYSIS (2.10.3)

- New text in COGEH relates to geological confidence in the mapping which is created, and the amount, quality and reliability of the data used in the geological interpretation.
- Required delineation to achieve an adequate level of geological confidence for the respective reserve classifications is a function of the reservoir type and depositional environment.
- For conventional geological traps, which can have significant variance in reserve quality and characterization over relatively short distances, the required delineation density may be greater than regional Resource plays.
Extrapolation from a control point

- Evaluators should ensure any extrapolation from existing information is understood and any documentation is based on relevant geological and engineering factors.
- For an extrapolation to be valid, a number of important elements must be evident and assigned the appropriate level of certainty:
  - e.g. the presence of the geological unit and the presence of hydrocarbons;
- For all Resource accumulations, the following all play a part in establishing the appropriate extrapolation distance from control:
  - e.g. depositional environment and depositional trends are the primary controls on presence of a formation,
  - diagenesis, the post positional alteration of sediment can destroy or create porosity and permeability, and
  - Potential change in pressure regimes and fluid properties.
Background:

- A regionally extensive, tight gas accumulation has been drilled and logged by a total of eight wells.
  - Three of these wells were subsequently completed, hydraulically fractured and either successfully flow tested or put on long term production, as illustrated in Figure 2-50.
- The pool is considered analogous to a similar accumulation located 20 miles away, which was originally developed on 80-acre spacing with vertical wells and has recently been drilled on 320-acre spacing with horizontal wells.
  - The operator of this new pool is expecting to drill to a similar well density using horizontal wells.
- The depositional environment is considered low energy and continuous, with no material changes expected over moderate distances of one to three miles.
- The available seismic data does not indicate the presence of faulting.
- Based on a thorough review of all the geological parameters available a net pay map, it has been constructed at the Best estimate level of confidence.
• This is a reasonable interpretation of which lands could be considered for Undeveloped Reserves
• Also, extent of known reservoir is provided (i.e. lands outside of here remain undiscovered)
ABANDONMENT, DECOMMISSIONING AND RECLAMATION (3.6.4)

- Inclusion of ADR in a reserves evaluation is on a “fit for purpose” basis
- COGEH recommended best practice is to include:
  - All ADR from the well to the custody transfer point
  - All ADR associated with future development
  - All ADR associated with active and inactive entities
- Industry must continue to include ADR for all reserves wells and major dedicated facilities in our evaluations to remain compliant with NI51-101
• It is important to note in the report what is and is not included in the evaluation:

- Property A:
  - Active asset
  - This includes: producers, injectors and dedicated facilities which support production
  - Inactive Wells

- Property B:
  - Inactive asset
• Evaluators should identify operating costs for **active and inactive** assets within a property

• Inactive assets include nonproducing wells or facilities and pipelines that have been shutdown plus their associated ADR liabilities

• Inactive costs should be included in an evaluation as a separate item at either property or corporate level and not burden producing entities

• It may also be appropriate to include costs for inactive properties at the corporate level

• Identify what is and is not included
MAINTENANCE CAPITAL

- Lease Operating Statements generally don’t include maintenance capital.
- Maintenance capital history and forecasts must be included in the evaluation.
- For most properties, a reasonable time frame to schedule maintenance capital for in-field facilities is 3 to 7 years.
- For large projects with significant facilities (gas processing, steam generation, offshore platforms, mining), ongoing maintenance capital is required for the life of the facility.
- Again, consider active and inactive assets.
CLARIFICATION OF OTHER ITEMS

• Reserves Reconciliations (4.6.2)
  – Product Type Transfers has been added as a category
  – Acquisition volumes are defined as the sum of the remaining Reserves as of the effective date plus the production between the closing date and the effective date
  – Changes in Reserves Category from Possible to Probable to Proved:
    • For Reserves assigned to an exploration discovery, a drilling extension, infill drilling, or an improved recovery project, that are initially categorized as possible only, they should be categorized as a proved or probable addition, in the same reserves change category, in the year when the Reserves are categorized as proved or probable
    • Any subsequent changes to the Proved or Probable Reserves assignment should be recorded as a technical revision
    • Therefore, if the change in category was not due technical change year-over-year, and was due to a function of timing or corporate intent, then it would be classified as a drilling addition
CLARIFICATION OF OTHER ITEMS

• Fit for Purpose Development Plans
  – Evaluations for year-end reporting include development plans consistent with Company’s intent/budget and past behavior
  – Evaluations for divestment/acquisition could include reasonably optimized development plans

• Company Gross Reserves in Production Sharing Contracts
  – Defined as Project Gross Sales Volume × Working Interest
DIFFERENCES WITH PRMS

• Consumed in Operations (CIO)
  – PRMS allows CIO volumes (example fuel gas) to be booked as reserves if allowed by regulator
  – COGEH does not allow booking CIO as reserves

• Split Conditions
  – PRMS has the same conditions for proved and unproved reserves
  – COGEH allows for different conditions for proved and unproved reserves (although this is rarely employed)
DIFFERENCES WITH PRMS

• Development Timing
  – Development of a project should be initiated within 5 years for PRMS
    • The scheduling will be dependent on the defined project
    • PRMS does also allow for development >5 years in specific cases with documentation
  – COGEH provides more specific guidance:
    • Development of small projects should be completed within 5 years
    • For large projects, significant capital expenditures should commence within 3 years for proved and 5 years for probable
    • Specific guidance is also provided as discussed earlier
ACKNOWLEDGEMENTS & QUESTIONS

• Doug Wright was Chair of the COGEH update
• Thanks to the oversight committee for their dedication to this project. They are as follows:

• The following individuals who contributed their time and energy to the subcommittees:

• The following individuals for their time and energy to review all or parts of the compiled document as submitted by the subcommittees:
  – Dave Perrot, P. Eng, Harry Helwerda, P. Eng, Rod Sidle, P. Eng, Gary Gozenbach, PE, Craig Burns, P. Geol, Randy Freeborn, P. Eng, Keith Macleod, P. Eng

• Thanks to the Calgary Chapter of the SPEE for significant contribution to this material. An additional slide deck is available at the following website: www.speecanada.org