

# RESERVOIR ENGINEERING

## for Geologists

---

### PRINCIPAL AUTHORS

Ray Mireault, P. Eng.

Lisa Dean, P. Geol.

### CONTRIBUTING AUTHORS

Nick Esho, P. Geol.

Chris Kupchenko, E.I.T.

Louis Mattar, P. Eng.

Gary Metcalfe, P. Eng.

Kamal Morad, P. Eng.

Mehran Pooladi-Darvish, P. Eng.



cspg.org

**fekete**  
fekete.com

Reservoir Engineering for Geologists was originally published as a fourteen-part series in the CSPG Reservoir magazine between October 2007 and December 2008.

## TABLE OF CONTENTS

---

Overview.....	03
COGEH Reserve Classifications.....	07
Volumetric Estimation .....	11
Production Decline Analysis.....	15
Material Balance Analysis.....	19
Material Balance for Oil Reservoirs.....	23
Well Test Interpretation.....	26
Rate Transient Analysis.....	30
Monte Carlo Simulation/Risk Assessment - Part 1.....	34
Monte Carlo Simulation/Risk Assessment - Part 2.....	37
Monte Carlo Simulation/Risk Assessment - Part 3.....	41
Coalbed Methane Fundamentals.....	46
Geological Storage of CO <sub>2</sub> .....	50
Reservoir Simulation.....	54

# Reservoir Engineering for Geologists

## Article I - Overview

by Ray Mireault, P. Eng., and Lisa Dean, P. Geol., Fekete Associates Inc..

Welcome to the first article in a series intended to introduce geologists to reservoir engineering concepts and their application in the areas of Corporate Reserve Evaluation, Production, Development, and Exploration.

Topics covered in the series are:

- Article 1: Overview
- Article 2: COGEH Reserve Classifications
- Article 3: Volumetric Estimation
- Article 4: Decline Analysis
- Article 5: Material Balance Analysis
- Article 6: Material Balance for Oil Reservoirs
- Article 7: Well Test Interpretation
- Article 8: Rate Transient Analysis
- Article 9: Monte Carlo Simulation
- Article 10: Monte Carlo Simulation (cont.)
- Article 11: Monte Carlo Simulation (cont.)
- Article 12: Coalbed Methane Fundamentals
- Article 13: Geological Storage of CO<sub>2</sub>
- Article 14: Reservoir Simulation

The format for each article will generally be to introduce the concept(s), discuss the theory, and illustrate its application with an example.

### ARTICLE DEFINITIONS AND USES

COGEH, the Canadian Oil and Gas Evaluation Handbook, Reserve Classifications provide a Canadian standard reference methodology for estimating reserve volumes according to reserve and resource category. There have been many recent changes in an attempt to achieve a "global standard" in order to ensure the public release of accurate, understandable reserve and resource estimations and classifications.

Volumetric Techniques are used to indirectly estimate Hydrocarbons in Place (OOIP and OGIP) from estimates of area, thickness, porosity, water saturation, and hydrocarbon fluid properties. Analogue or theoretical estimates for hydrocarbon recovery are then applied to estimate recoverable hydrocarbons. These techniques are utilized prior to the acquisition of sufficient production data to allow a more rigorous determination of reserves and resource estimates. These methods are therefore primarily used for evaluating new, non-producing pools and the evaluation of new petroleum basins.

Decline analysis techniques extrapolate the historical performance trend to an economic

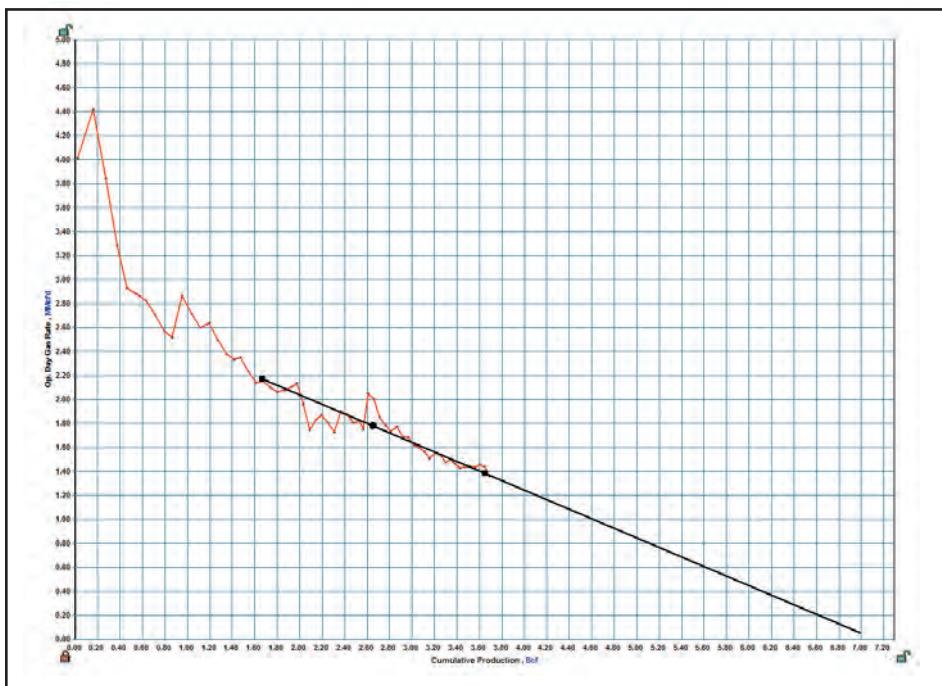


Figure 1.1. Traditional decline analysis - Rate vs. Cum. Prod.

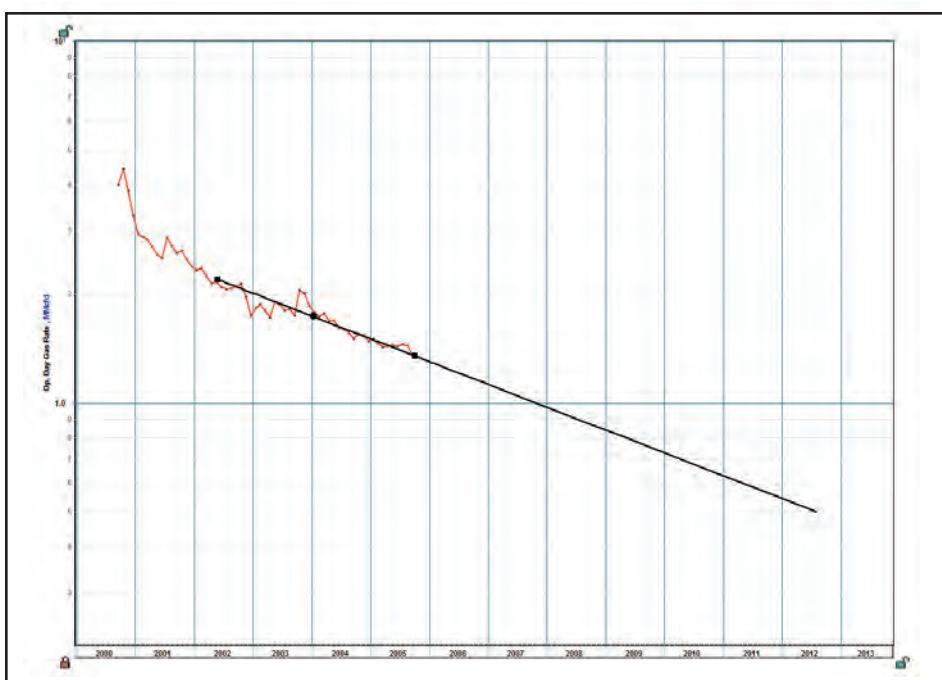


Figure 1.2. Traditional decline analysis - Rate vs. Time.

production limit or cutoff to forecast the expected ultimate recovery (EUR). The method plots the production rate through the production history (time) and records the production rate decline as cumulative production increases (Figures 1.1 and 1.2).

In theory it is only applicable to individual wells, but in practice extrapolations of group production trends often provide acceptable approximations for EUR. Two key assumptions are that past trends represent the full capability of the producing entity and

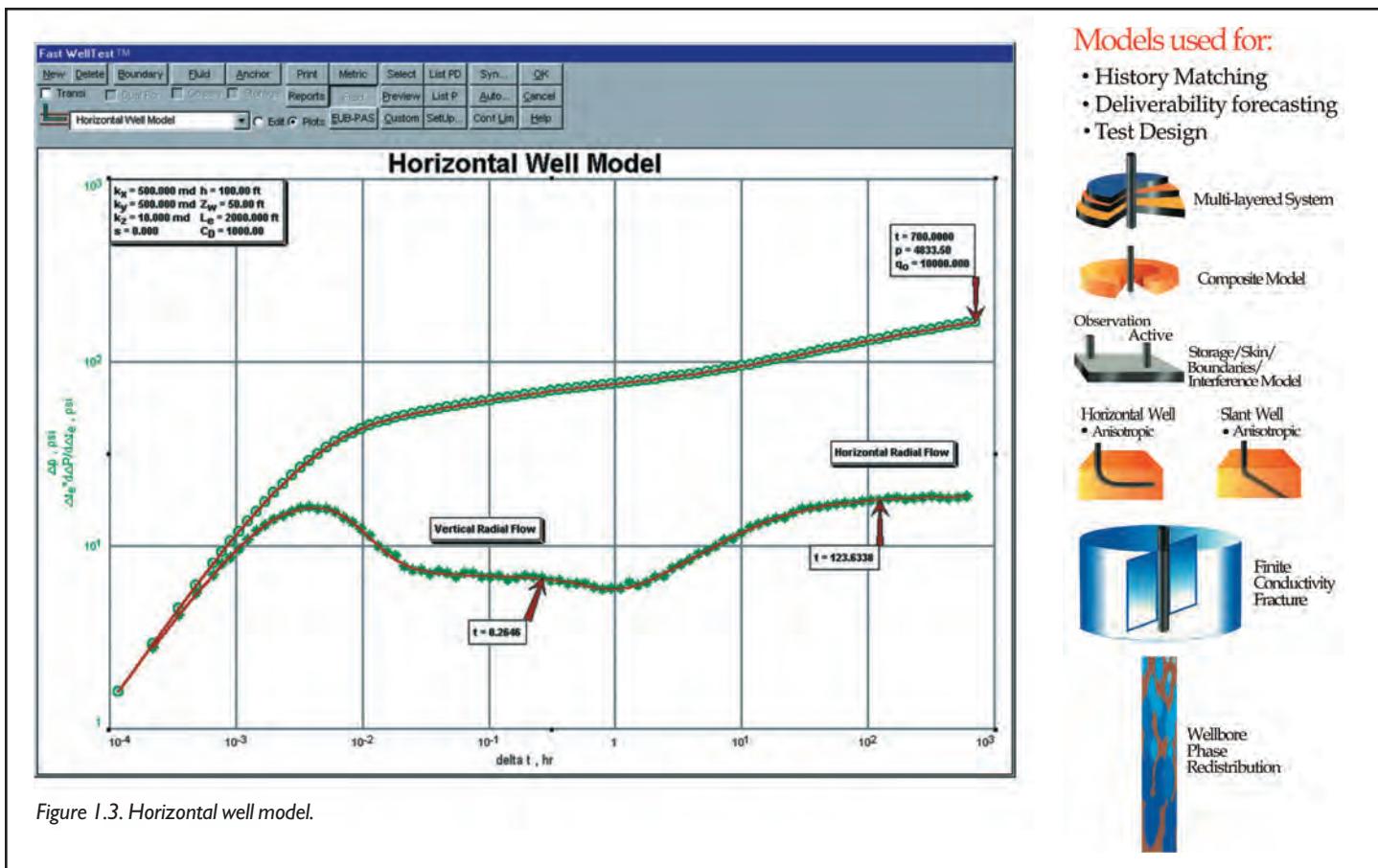


Figure 1.3. Horizontal well model.

that the trends and operating practices continue into the future. Deviations from theoretical performance can help identify wells and areas that are underperforming. Well workovers to resolve mechanical problems or changes in operating practices can enhance performance and increase recovery. The presence of pressure maintenance by an aquifer may make this method inappropriate to use. This technique is also more reliable than volumetric methods when sufficient data is available to establish a reliable trend line.

Material balance techniques are used to estimate hydrocarbons in place (OOIP and OGIP) from measurements of fluid production and the resultant change in reservoir pressure caused by that production. The technique requires accurate estimates of fluid properties, production volumes, and reservoir pressure. Estimates for hydrocarbon recovery, based on fluid properties and analogue producing pools/formations, are then applied to estimate recoverable hydrocarbons. These methods are more reliable than volumetric methods as long as there is sufficient data to establish the relationship.

Well tests and the subsequent pressure transient analyses are used to determine fluids present in the reservoir, estimate well productivity, current reservoir pressure,

permeability, and wellbore conditions from mathematical flow equations and dynamic pressure buildup measurements. The

technique requires that a well be produced for a period of time and then shut-in for an appropriate length of time. Analysis inputs

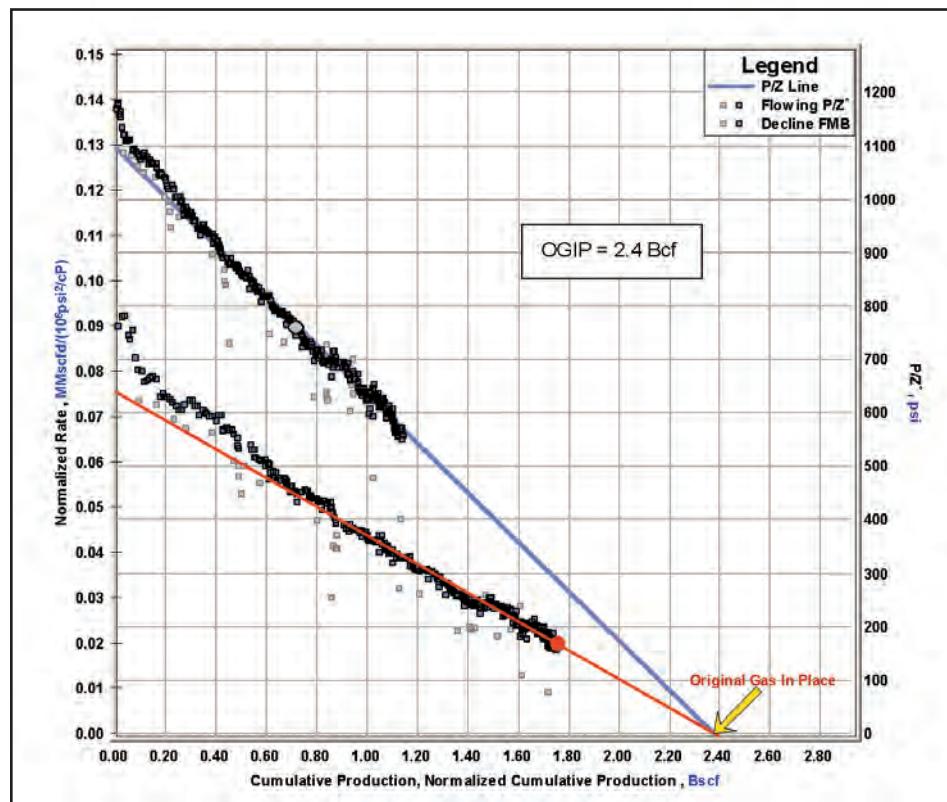
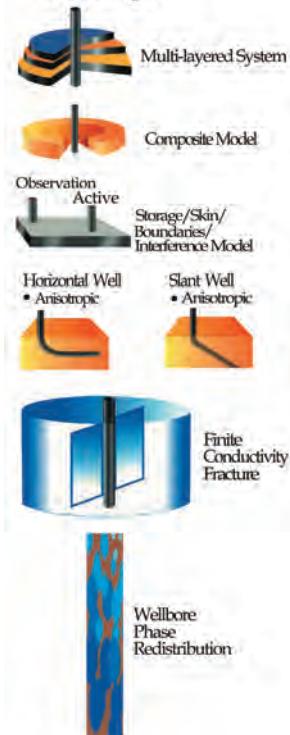


Figure 1.4. Flowing material balance.

## Models used for:

- History Matching
- Deliverability forecasting
- Test Design



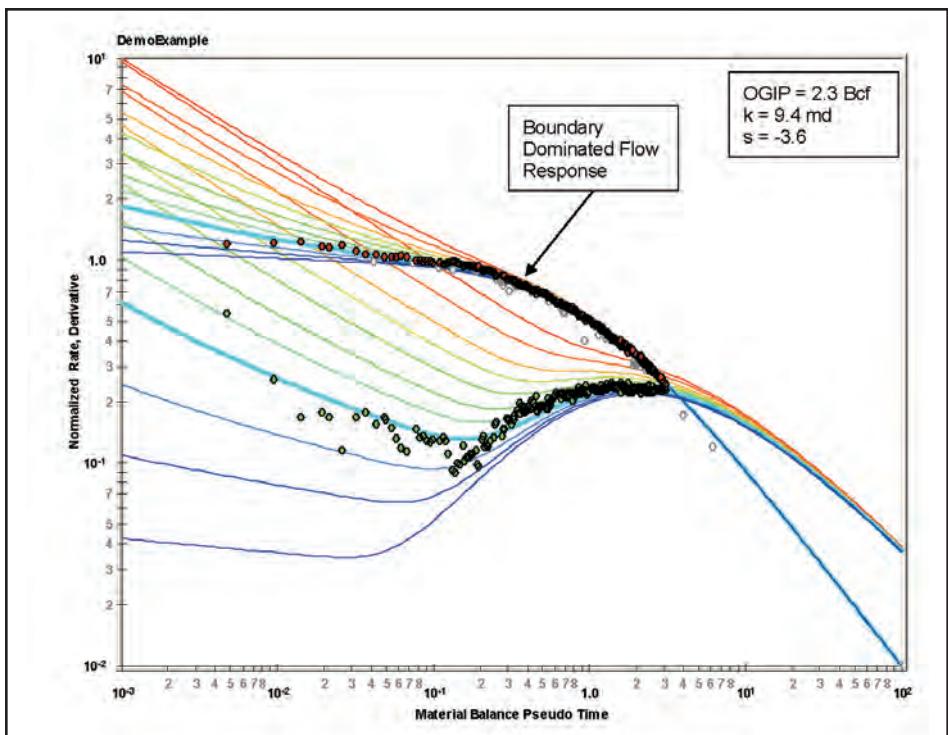


Figure 1.5. Blasingame typecurve analysis.

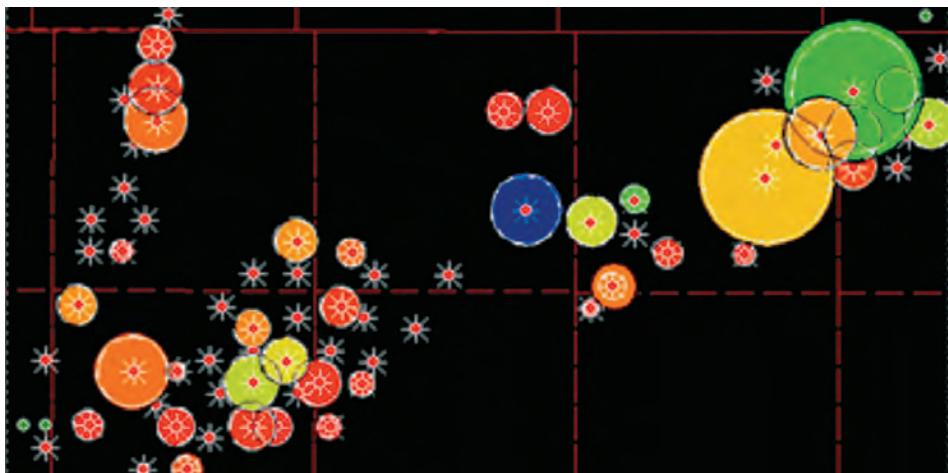


Figure 1.6. Visualization of results.

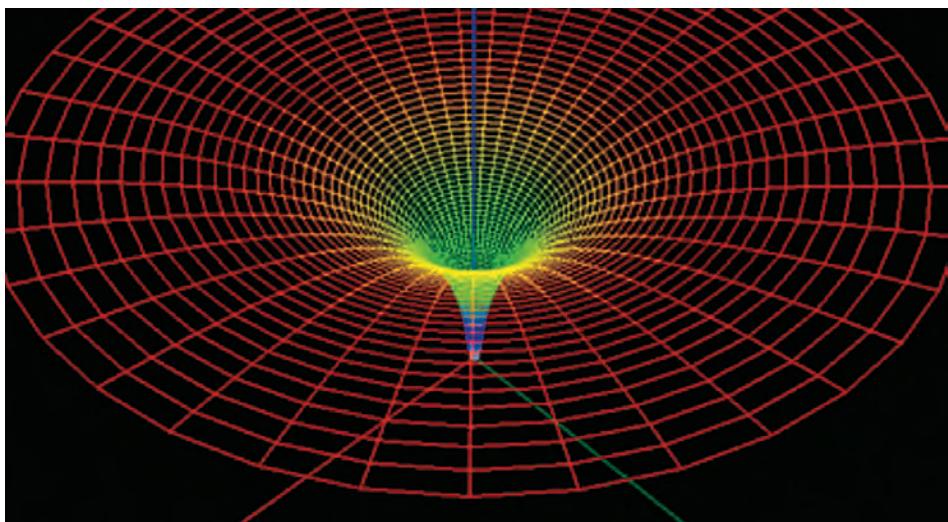


Figure 1.7. Pressure profile from numerical model.

include fluid viscosity, rock properties, net pay thickness of the producing interval, and the mechanical configuration of the wellbore. An adequate buildup provides information on the reservoir flow pattern near the wellbore, identifies restricted reservoirs, and can sometimes infer the geometric shape of the well's drainage area (see Figure 1.3).

Rate transient analysis (RTA), also known as advanced decline analysis is a relatively recent development that uses well flowing pressures to characterize well and reservoir properties and estimate in-place volumes. This technique has been made available by the introduction of SCADA (Supervisory Control and Data Acquisition) data capture systems that generally provide the frequency of flow and pressure information required for real-life application (flowing material balance and type curve analysis – see Figures 1.4 and 1.5). Since pressure information can be captured without shutting the well in and without the loss of cash flow, the frequency of “testing” can be significantly increased and changes in operating performance identified more quickly than is practical with conventional testing.

Monte Carlo simulation is used to deal with the uncertainty in every input parameter value in the volumetric equation. Instead of a single number, it allows the geologist to provide a value range for areal extent, pay thickness, porosity, water saturation, reservoir pressure, temperature, fluid properties, and recovery factor. Multiple (typically 10,000) iterations are run to generate a probable range of values for in-place and recoverable hydrocarbons (Figure 1.6). The simulation is especially applicable to play and resource assessments.

Numerical reservoir simulation uses material balance and fluid flow theory to predict fluid movement through three-dimensional space. The inputs of geometric shape of the deposit, the rock, and fluid properties must be determined from other methods to deal with the nonuniqueness of the forecasts. However, it has the ability to visually integrate the geological and geophysical interpretation with the analytical approach to reservoir analysis (Figure 1.7).

Although different techniques are used in different situations, a major purpose of reservoir engineering is to estimate recoverable oil or gas volumes and forecast production rates through time. Forecasts of production rate and cumulative volumes are a key input for the following:

- Exploration play assessment,
- Development drilling locations,

- Accelerated production from a producing pool,
- Rank and budgeting of potential exploration and development expenditures,
- Corporate reserve evaluations.

The different techniques also have different applications at different times in the life of a field or prospect. For example, the initial stages of exploration may require volumetric estimates based upon analogue data due to the lack of existing well information and estimating volumes with Monte Carlo simulation. Volumetric estimates based upon actual well data may be the next step after exploration drilling and testing has proven successful. As development and production commence, SCADA frequency production and pressure measurements can be obtained for RTA analysis. Monthly production volumes provide the data for material balance and decline analysis techniques.

As production continues, the accuracy and reliability of the estimates obtained from RTA, material balance, and decline analysis increases. Integrating all the techniques provides more reliable answers than relying solely on any one method. In addition, integrating the techniques can lead to additional hydrocarbon discoveries and/or increased recovery from known accumulations.

Articles two through nine address the main topics of reservoir engineering. The remaining articles will focus on play types that are presently of interest to the industry. Included in this group of plays are coalbed methane concepts and interpretation (Figures 1.8 and 1.9), tight gas, shale gas, and an overview of secondary and tertiary oil recovery methods.

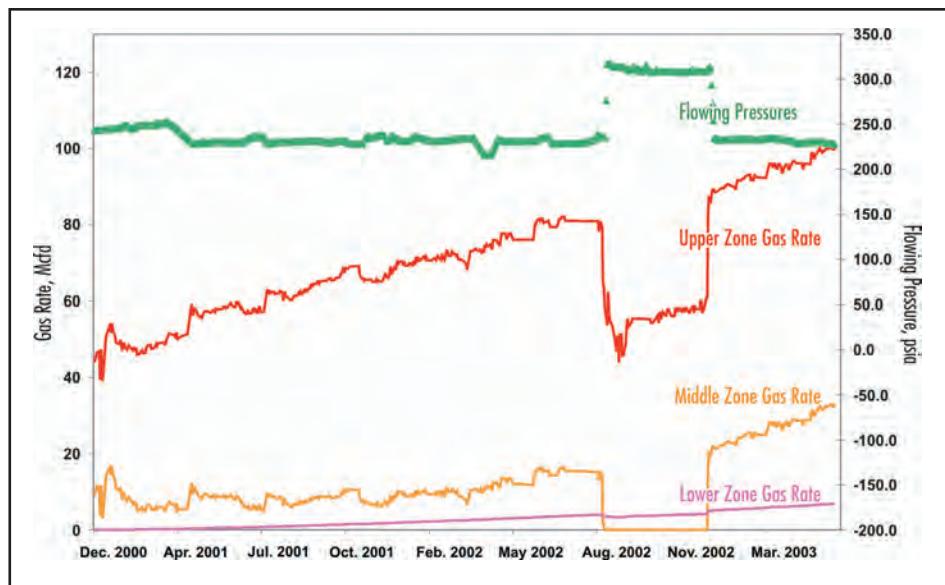


Figure 1.8. Historical rates vs. time.

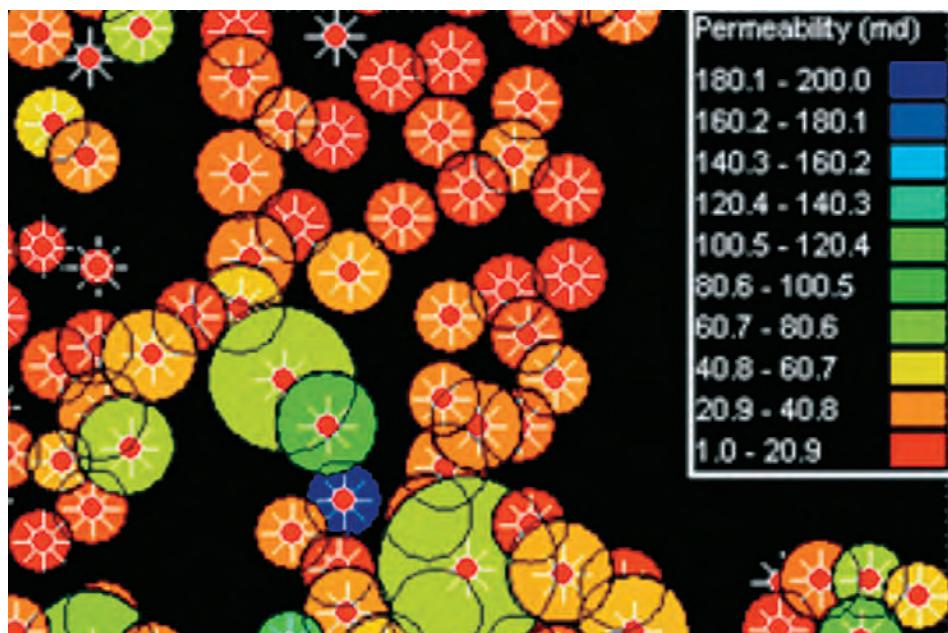


Figure 1.9. Drainage area and permeability.



# Reservoir Engineering for Geologists

## Article 2 - COGEH Reserve Classifications

by Gary Metcalfe, P. Eng., Vice President Evaluations

In 2004, the Royal Dutch Shell Group reported five separate write-downs of 3,900 MSTB, 250 MSTB, 200 MSTB, 100 MSTB, and one undisclosed volume. In that same year, El Paso reported a 41% write-down in reserves from 4,500 BCF to 2,600 BCF. Where did the reserves go? The answer is ...nowhere! These write-downs resulted from misinterpretation of standards and guidelines for reserve classification. The reported oil and gas volumes likely exist; it was just a matter of premature classification into the proved reserves category.

The Canadian Securities Administrators (CSA), through National Instrument 51-101 (NI 51-101), sets the standards for disclosure of oil and gas activities for companies listed

on Canadian stock exchanges. The definitions and standards for reserve appraisals and evaluations are defined in the Canadian Oil and Gas Evaluation Handbook (COGEH).

Reserves are the estimated remaining quantities of oil and natural gas and related substances anticipated to be recoverable from known accumulations based on analysis of drilling, geological, geophysical, and engineering data; established technology; and specific economic conditions.

Under the COGEH definitions, the reported proved reserves are those estimated with a high degree of certainty to be recovered, probable reserves are less certain to be recovered than proved, and possible are

those less certain to be recovered than probable. The degree of certainty is defined as:

**Proved:** 90% probability of meeting or exceeding the estimated proved volume (P90).

**Proved plus probable:** 50% probability of meeting or exceeding the sum of the estimated proved plus probable volume (P50).

**Proved plus probable plus possible:** 10% probability of meeting or exceeding the sum of the estimated proved plus probable plus possible volume (P10).

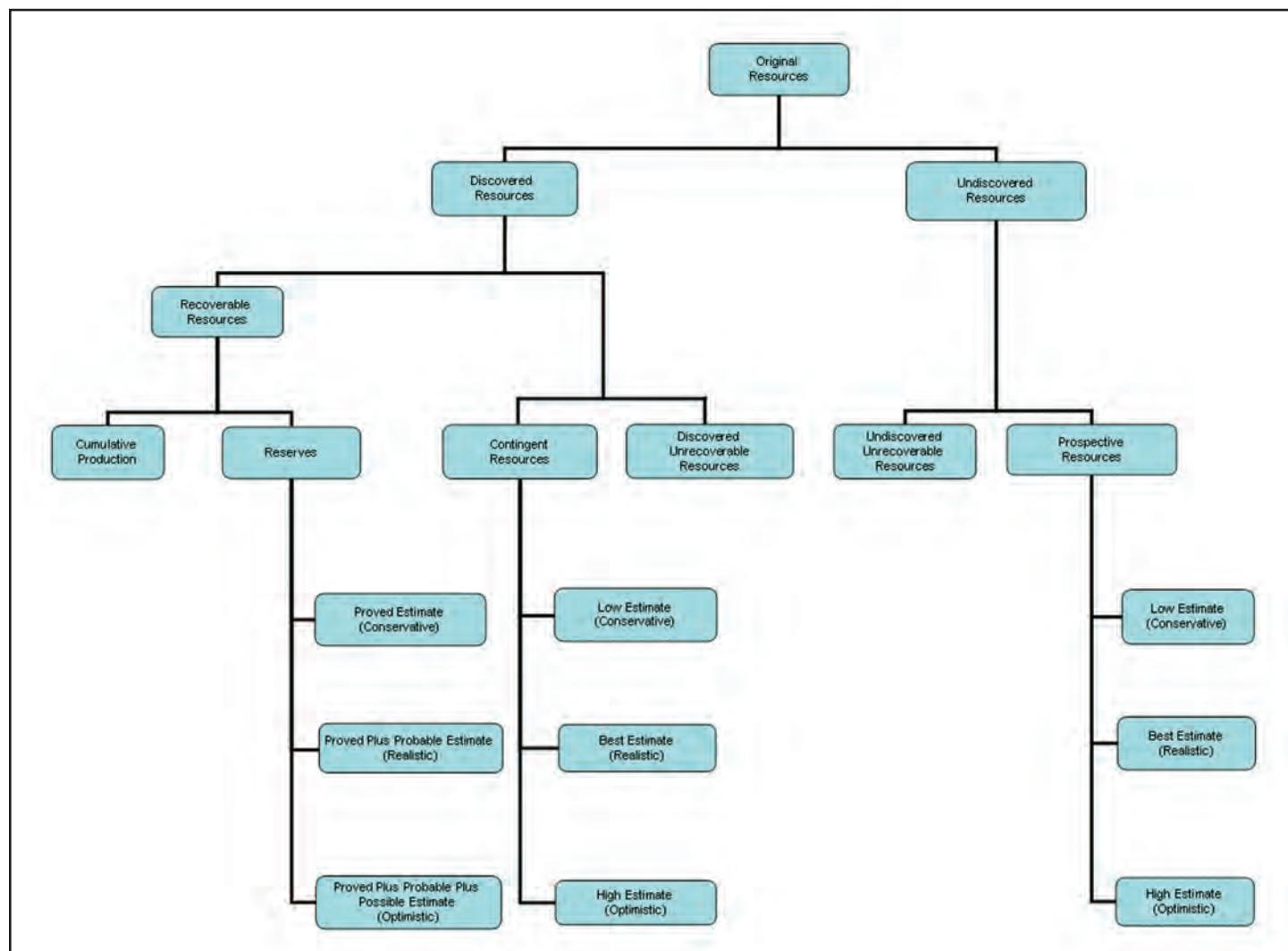


Figure 2.1. COGEH reserves and resources classification.



Each of the reserve classifications can be divided into Developed and Undeveloped categories, with the developed category further subdivided into Producing and Non-producing.

### REQUIREMENTS FOR RESERVE CLASSIFICATION

Within COGEH, there are requirements and procedures for classifying reserves. The conditions that must be met to assign reserves are:

- Drilling – accumulation must have a well;
- Testing – accumulation must have evidence of commercial production from a test;
- Economics – for producing reserves, cash flow and NPV must be positive; for undeveloped reserves, a reasonable return on investment must be demonstrated; and
- Regulatory – prohibitive government restraints must be incorporated when estimating appropriate levels of risk.

### METHODS OF ESTIMATING RESERVES

Reserves can be estimated using deterministic or probabilistic methods:

**Deterministic:** A single value assigned for each input parameter of the reserves calculations is used. The appropriate value for each reserve category must be selected. The majority of reserves in Canada are estimated using this method.

**Probabilistic:** A full range of values are used for each input parameter into the reserve calculation. Reserve estimates can be extracted from a Monte Carlo type of analysis at the various confidence levels P90, P50, P10, etc. This method pertains mainly to volumetric evaluations prior to the onset of production.

Both the deterministic and probabilistic methods will be presented in subsequent articles.

### AGGREGATION OF RESERVES

Under COGEH, the P90, P50, and P10 values are reported at the corporate level, not at the entity (well/property) level. When deterministic methods are used, simple summation of all individual entities within a portfolio provides the aggregate total.

With probabilistic methods, reserve distributions for the individual entities must be combined in accordance with the laws of probability to determine the correct distribution for the aggregate. The arithmetic P90 summation will be less than the P90 of the aggregate (i.e., too conservative) and

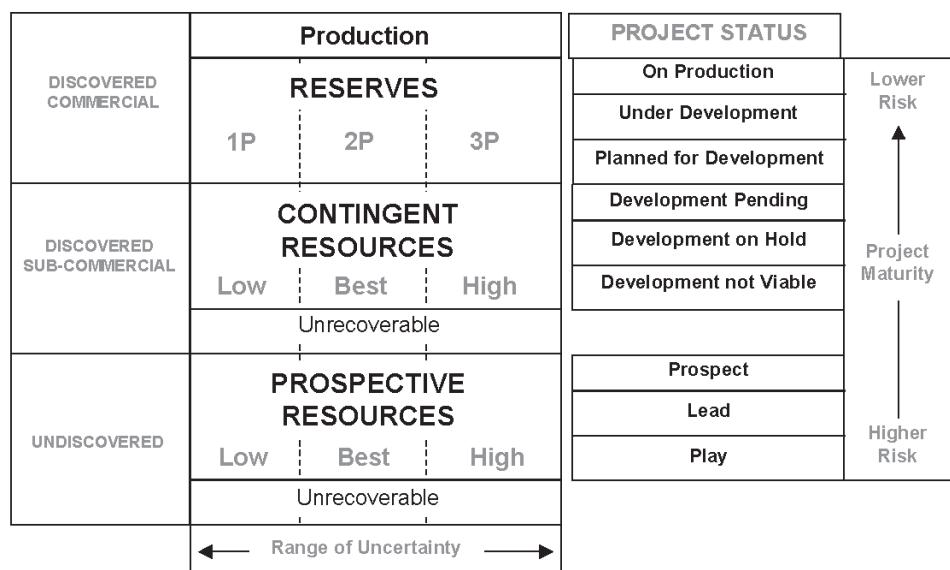


Figure 2.2. Project status categories / commercial risk (sourced from SPE Oil and Gas Committee Final Report - December 2005).

conversely the arithmetic summation of P10 will exaggerate the upside and be optimistic compared to the P10 from the aggregate distribution.

For reserve reporting to an investment type audience, probabilistic aggregation poses a problem as a P90 aggregate type corporate disclosure cannot be allocated back or identified in any individual well or property or prospect.

### RESOURCES

The NI 51-101 regulations also allow for the disclosure of information for properties with no attributed reserves. The general reserve / resource classifications as they are defined in COGEH (see Figure 2.1: COGEH Reserves and Resources Classification, p. 30), are as follows:

Resources are limited to discovered (known) and undiscovered accumulations. Contingent resources are discovered but not currently economic. Prospective resources are undiscovered but are technically viable and economic to recover. These resources are further classified into Low (conservative), Best (realistic) and High (optimistic) estimates.

There are no detailed guidelines in COGEH for resource appraisals; however, COGEH does recommend probabilistic evaluation. If resources are submitted in an NI 51-101 report, disclosure must include volumes, net pay, areal extent, flow rates, land, seismic, wells, exploration / development programs, and capital expenditures. The explicit disclosure of risk and / or probability of success are also required. This is problematic in that a single probability estimate is not possible to calculate.

### RECENT DEVELOPMENTS IN RESERVES CLASSIFICATIONS

#### International properties

The scrutiny of oil and gas reserves continues to increase, especially as more and smaller Canadian issuers are competing in the U.S. and international markets. The financial world is attempting to create a set of global accounting standards through the International Accounting Standards Board (IASB). The IASB expects reserve estimates to reflect expected values rather than conservative (proved) estimates and believes reserve estimates should be presented as a range reflecting uncertainty.

#### Petroleum Resource Management System (PRMS)

Establishing a rigorous, harmonized, and universal reserves and resources classification system for all stakeholders (oil industry, accountants, regulators, business / financial analysts, investors, and governments) is an ongoing process. The recent 2007 SPE / AAPG / WPC / SPEE (etrp;ei, Resipre <amage,emt Suste, (PRMS) has been proposed as the new standard for petroleum reserve and resource classification, definition, and guidelines. This system has a "commerciality" or "project maturity" subclass (see Figure 2.2: Project Status Categories / Commercial Risk).

The United Nations Economic Commission for Europe (UNECE) and the United Nations Framework Classification for Fossil Energy and Minerals Resources (UNFC) both recognize project maturity (along with economic viability and geological knowledge) as the basic criteria for categorization and alignment of energy management and financial reporting. To this end, it appears the UNFC and the PRMS definitions are compatible.

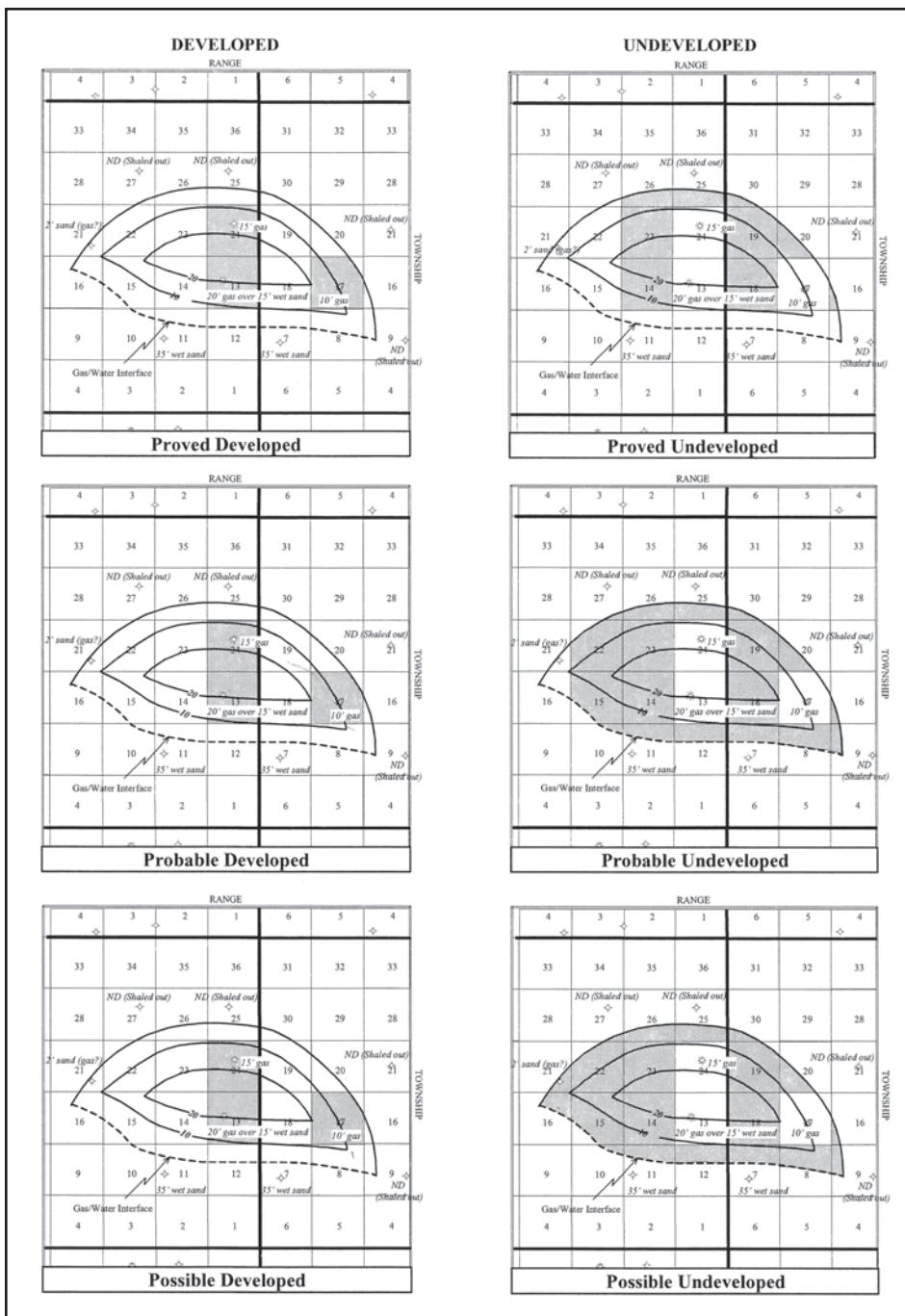


Figure 2.3. Multi-well gas pool example reserves classification (sourced from Canadian Oil and Gas Evaluation Handbook, Volume 2, Section 6 - Procedures for estimation and classification of reserves, Figure 6-2B).

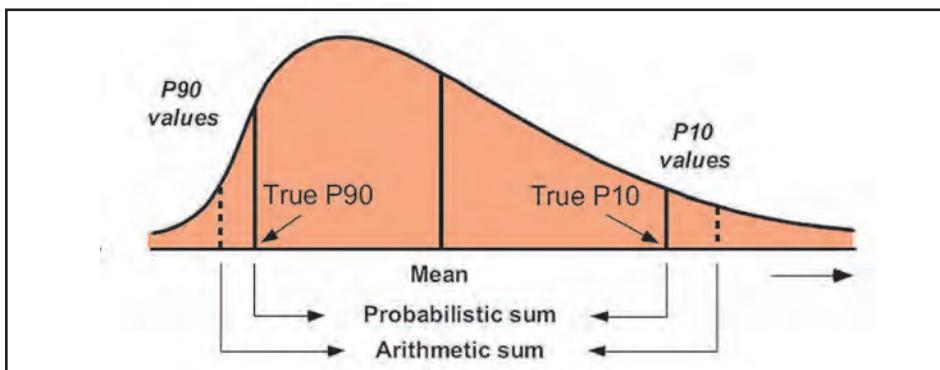


Figure 2.4. Aggregation (summation) issues (sourced from Kemirmen, Ferruh, Society of Petroleum Engineers Paper #103434, Figure 10).

PRMS is an ongoing, long-term process. If these new standards are developed and implemented, Canadian and U.S. regulators must respond positively and provide regulatory enforcement in order to gain the trust of investors and have credibility in the marketplace.

### Unconventional Reserves and Resources

The industry is investing heavily in technology to improve recovery and processes for unconventional extra heavy oil, tight gas sands, CBM, oil shales, and gas hydrates. The classification and technical standards for these unconventional reserves / resources must conform to the system used for conventional reservoirs.

The COGEH Volume 3 “Detailed Guidelines for Estimation and Classification of CBM Reserves and Resources” is in draft stage at the time of writing this article. This huge undertaking is likely the first publication dealing specifically with classifying, defining, and quantifying unconventional reserves and resources.

### Reserves Evaluator Training

The SPEE/WPC/AAPG and SPE have formed the Joint Committee on Reserves Evaluator Training (JCORET) to investigate training courses for reserve evaluators that focus, in part, on reserves and resources definitions, classification, and applications. Discussions on qualifications and standards for professional reserve evaluators and auditors are ongoing.

### CONCLUSION

The reason for NI 51-101 and COGEH is to provide the shareholder/investor/stakeholder with consistent and reliable reserves information using standardized reporting guidelines in a format that can be widely understood. While the COGEH framework allows for definitions and classifications for current conventional and unconventional reserves and resources, the classification and definition of reserves is an ever-evolving process. COGEH will continue to be modified to adapt to new technology and standardization in a global economy.

### REFERENCES

- Kemirmen, Ferruh, 2007. “Reserves Estimation: The Challenge for the Industry,” Society of Petroleum Engineers Paper #103434, In Journal of Petroleum Technology May 2007, P80-89.

Canadian Oil and Gas Evaluation Handbook, First Edition, November 1, 2005, Volume 2, Detailed Guidelines for Estimation and Classification of Oil and Gas Resources and

Reserves. Section 6: Procedures for  
Estimation and Classification of Reserves,  
2005.

Oil and Gas Reserves Committee, Mapping  
Subcommittee Final Report – December  
2005: Comparison of Selected Reserves  
and Resource Classifications and  
Associated Definitions, 2005. Richardson,  
Texas: Society of Petroleum Engineers.  
<http://www.spe.org/web/ogr/>  
OGR\_mapping\_Final\_Report\_15Dec05.pdf.

---



# Reservoir Engineering for Geologists

## Article 3 – Volumetric Estimation

by Lisa Dean, P. Geol., Fekete Associates Inc..

You have been asked to:

- Evaluate the properties that are for sale in a data room.
- Determine whether to participate in a prospect.
- Calculate the potential reserves encountered by a discovery well.
- Identify the upside potential in a mature field.

In all these situations, the bottom line is “how much oil or gas exists and can be produced, and what will be the return on investment?” This article addresses this question.

Volumetric estimation is the only means available to assess hydrocarbons in place prior to acquiring sufficient pressure and production information to apply material balance techniques. Recoverable hydrocarbons are estimated from the inplace estimates and a recovery factor that is estimated from analogue pool performance and/or simulation studies.

Therefore, volumetric methods are primarily used to evaluate the in-place hydrocarbons in new, non-producing wells and pools and new petroleum basins. But even after pressure and production data exists, volumetric estimates provide a valuable check on the estimates derived from material balance and decline analysis methods (to be discussed in upcoming Reservoir issues).

### VOLUMETRIC ESTIMATION

Volumetric estimation is also known as the “geologist’s method” as it is based on cores, analysis of wireline logs, and geological maps. Knowledge of the depositional environment, the structural complexities, the trapping mechanism, and any fluid interaction is required to:

- Estimate the volume of subsurface rock that contains hydrocarbons. The volume is calculated from the thickness of the rock containing oil or gas and the areal extent of the accumulation (Figure 3.1).
- Determine a weighted average effective porosity (See Figure 3.2).
- Obtain a reasonable water resistivity value and calculate water saturation.

With these reservoir rock properties and utilizing the hydrocarbon fluid properties,

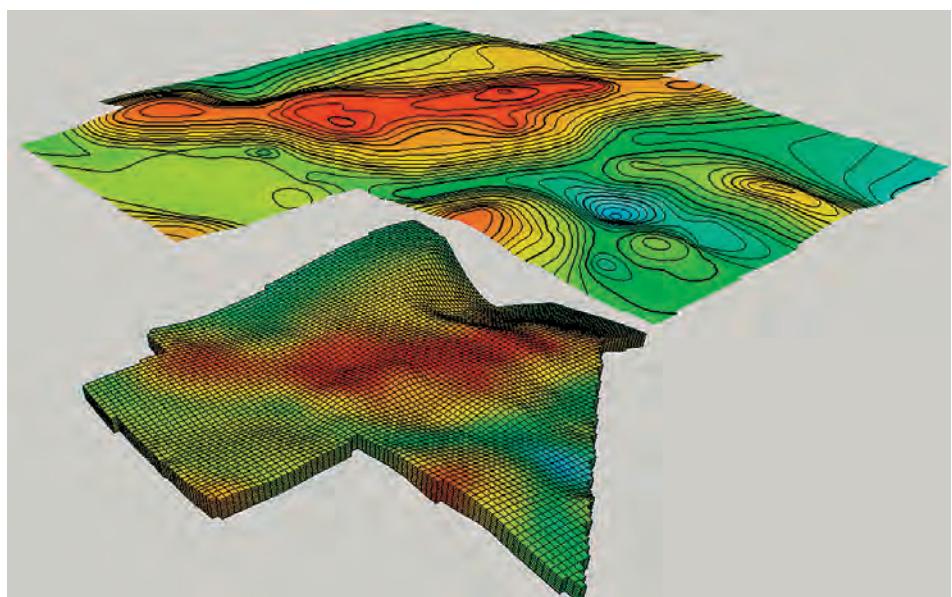


Figure 3.1. Areal extent of rock volume accumulation.

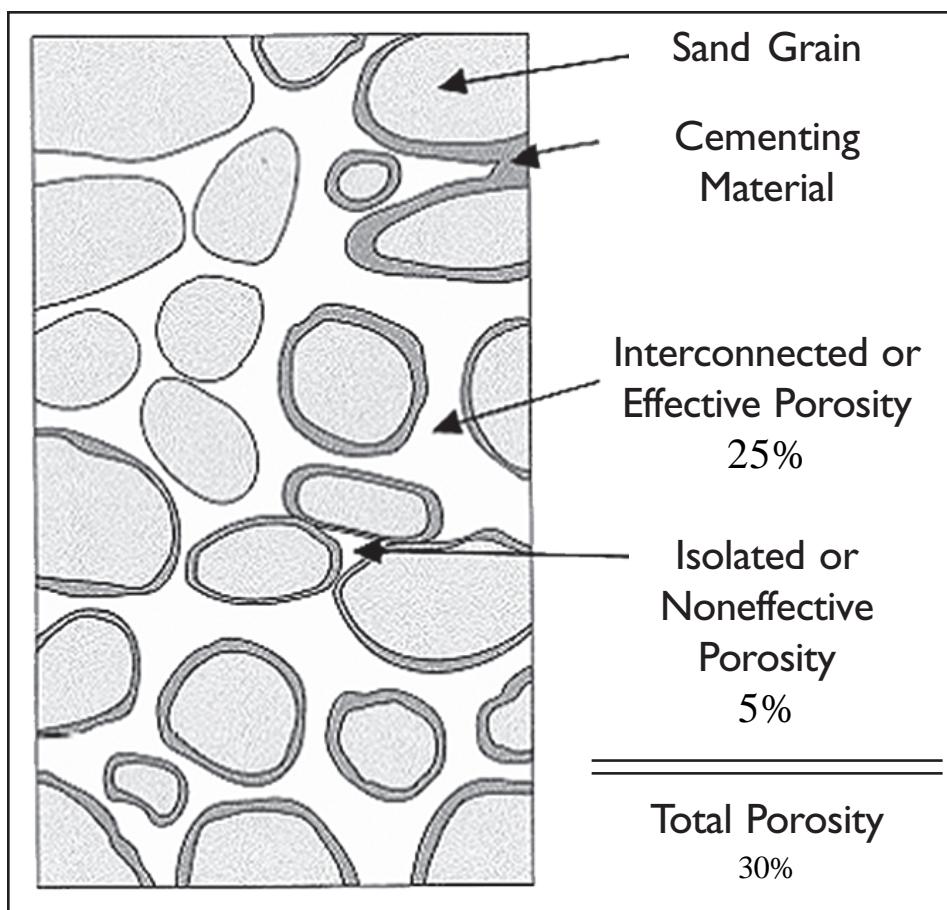


Figure 3.2. Weighted average effective porosity.



original oil-in-place or original gas-in-place volumes can be calculated.

For **OIL RESERVOIRS** the original oil-in-place (OOIP) volumetric calculation is:

**Metric:**

$$\text{OOIP (m}^3\text{)} = \text{Rock Volume} * \emptyset * (1 - S_w) * I/B_o$$

Where: Rock Volume ( $\text{m}^3$ ) =  $10^4 * A * h$

A = Drainage area, hectares (1 ha =  $10^4 \text{ m}^2$ )

h = Net pay thickness, metres

$\emptyset$  = Porosity, fraction of rock volume available to store fluids

$S_w$  = Volume fraction of porosity filled with interstitial water

$B_o$  = Formation volume factor ( $\text{m}^3/\text{m}^3$ ) (dimensionless factor for the change in oil volume between reservoir conditions and standard conditions at surface)

$I/B_o$  = Shrinkage (Stock Tank  $\text{m}^3/\text{reservoir m}^3$ ) = volume change that the oil undergoes when brought to the earth's surface due to solution gas evolving out of the oil.

**Imperial:**

$$\text{OOIP (STB)} =$$

$$\text{Rock Volume} * 7,758 * \emptyset * (1 - S_w) * I/B_o$$

Where: Rock Volume (acre feet) =  $A * h$

A = Drainage area, acres

h = Net pay thickness, feet

7,758 = API Bbl per acre-feet (converts acre-feet to stock tank barrels)

$\emptyset$  = Porosity, fraction of rock volume available to store fluids

$S_w$  = Volume fraction of porosity filled with interstitial water

$B_o$  = Formation volume factor (Reservoir Bbl/STB)

$I/B_o$  = Shrinkage (STB/reservoir Bbl)

To calculate **recoverable oil volumes** the OOIP must be multiplied by the Recovery Factor (fraction). The recovery factor is one of the most important, yet the most difficult variable to estimate. Fluid properties such as formation volume factor, viscosity, density, and solution gas/oil ratio all influence the recovery factor. In addition, it is also a function of the reservoir drive mechanism and the interaction between reservoir rock and the fluids in the reservoir. Some industry standard oil recovery factor ranges for various natural drive mechanisms are listed below:

Solution gas drive 2 – 30%

Gas cap drive 30 – 60%

Water drive 2 – 50%

Gravity Up to 60%

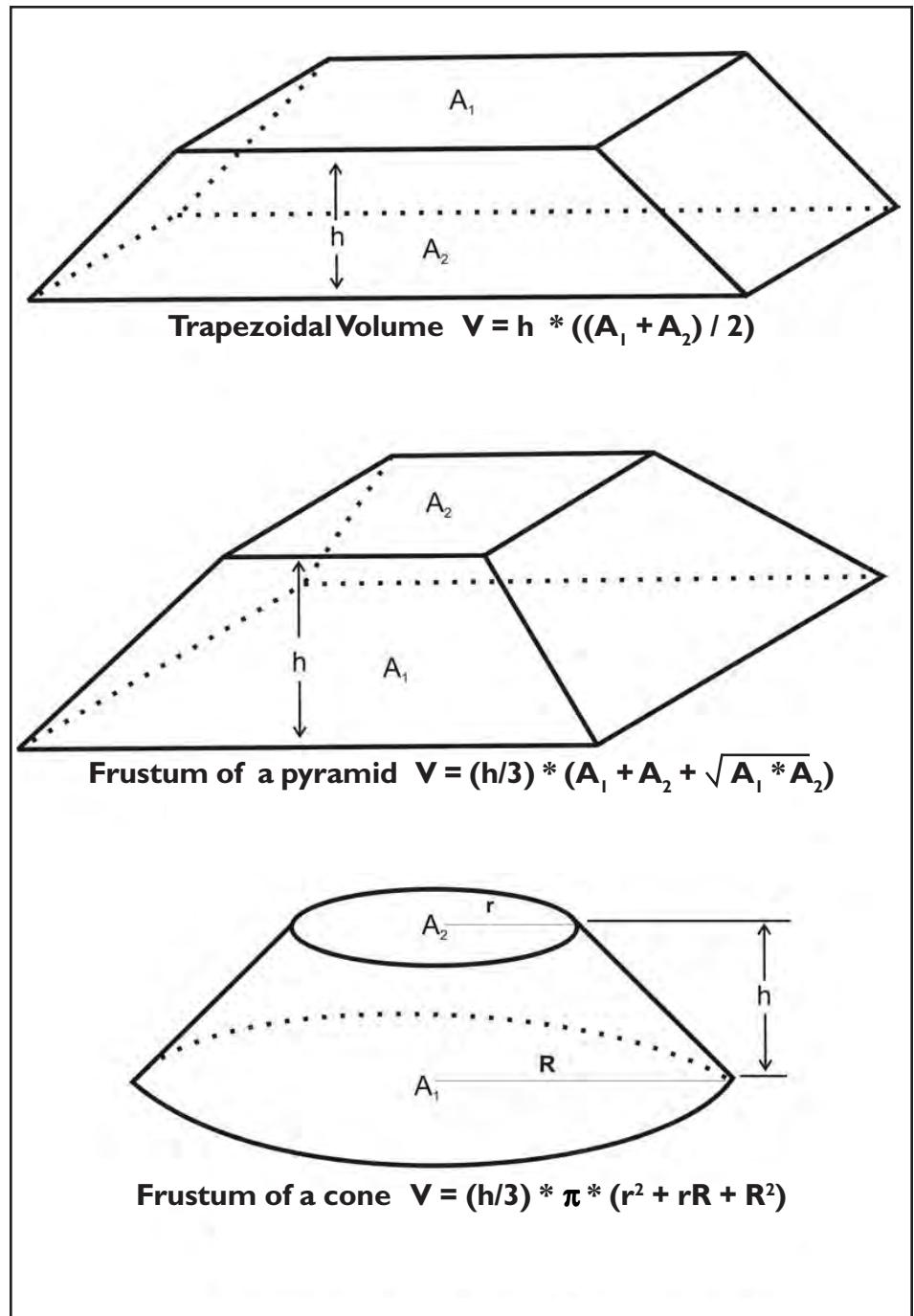


Figure 3.3. Volumetric rules: Trapezoidal, pyramidal, and cone.

For **GAS RESERVOIRS** the original gas-in-place (OGIP) volumetric calculation is:

$T_s$  = Base temperature, standard conditions, °Kelvin (273° + 15°C)

$P_s$  = Base pressure, standard conditions, (101.35 kPa)

$T_f$  = Formation temperature, °Kelvin (273° + °C at formation depth)

$P_i$  = Initial Reservoir pressure, kPa

$Z_i$  = Compressibility at  $P_i$  and  $T_f$

**Metric:**

$$\text{OGIP (10}^3\text{ m}^3\text{)} =$$

$$\text{Rock Volume} * \emptyset * (1 - S_w) * ((T_s * P_i) / (P_s * T_f * Z_i))$$

Where: Rock Volume ( $\text{m}_3$ ) =  $10^4 * A * h$

A = Drainage area, hectares (1 ha =  $10^4 \text{ m}^2$ )

h = Net pay thickness, metres

$\emptyset$  = Porosity, fraction of rock volume available to store fluids

$S_w$  = Volume fraction of porosity filled with interstitial water

**Imperial:**

$$\text{OGIP (MMCF)} =$$

$$\text{Rock Volume} * 43,560 * \emptyset * (1 - S_w) * ((T_s * P_i) / (P_s * T_f * Z_i))$$

Where: Rock Volume (acre feet) =  $A * h$

$A$  = Drainage area, acres (1 acre =

43,560 sq. ft)

$h$  = Net pay thickness, feet

$\emptyset$  = Porosity, fraction of rock volume available to store fluids

$S_w$  = Volume fraction of porosity filled with interstitial water

$T_s$  = Base temperature, standard conditions, °Rankine ( $460^\circ + 60^\circ F$ )

$P_s$  = Base pressure, standard conditions, 14.65 psia

$T_f$  = Formation temperature, °Rankine ( $460^\circ + F$  at formation depth)

$P_i$  = Initial Reservoir pressure, psia

$Z$  = Compressibility at  $P_i$  and  $T_f$

To calculate recoverable gas volumes, the OGIP is multiplied by a recovery factor. Volumetric depletion of a gas reservoir with reasonable permeability at conventional depths in a conventional area will usually recover 70 to 90% of the gas-in-place. However, a reservoir's recovery factor can be significantly reduced by factors such as: low permeability, low production rate, overpressure, soft sediment compaction, fines migration, excessive formation depth, water influx, water coning and/or behind pipe cross flow, and the position and number of producing wells. As an example, a 60% recovery factor might be appropriate for a gas accumulation overlying a strong aquifer with near perfect pressure support.

### Rock Volume Calculations ( $A * h$ )

Reservoir volumes can be calculated from net pay isopach maps by planimetering to obtain rock volume ( $A * h$ ). To calculate volumes it is necessary to find the areas between isopach contours. Planimetering can be performed by hand or computer generated. Given the areas between contours, volumes can be computed using; Trapezoidal rule, Pyramidal rule, and/or the Peak rule for calculating volumes (see Figure 3.3).

### Net pay

Net pay is the part of a reservoir from which hydrocarbons can be produced at economic rates, given a specific production method. The distinction between gross and net pay is made by applying cut-off values in the petrophysical analysis (Figure 3.4). Net pay cut-offs are used to identify values below which the reservoir is effectively non-productive.

In general, the cut-off values are determined based on the relationship between porosity, permeability, and water saturation from core data and capillary pressure data. If core is unavailable, estimation of a cut-off can be derived from offset well information and

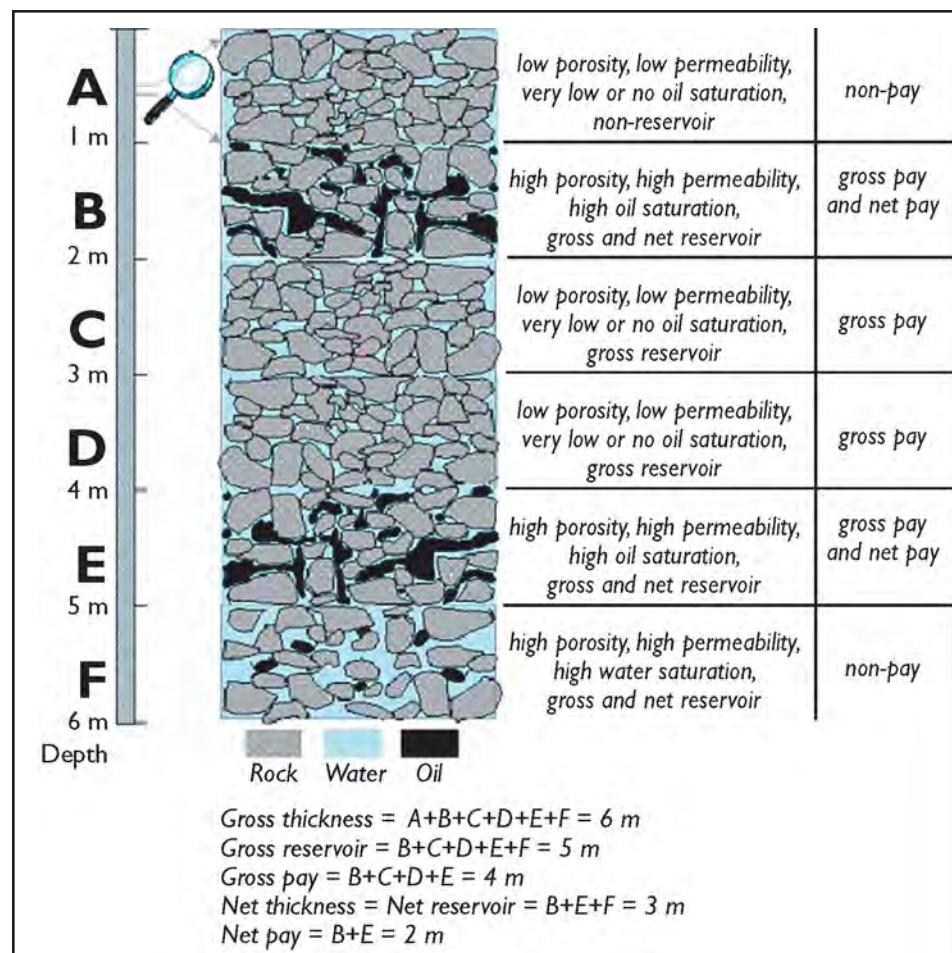


Figure 3.4. Gross and net pay distinction (Etris and Stewart, 2003).

comparative log signatures.

### Porosity and Water Saturation

Porosity values are assigned as an average over a zone (single well pool) or as a weighted average value over the entire pay interval using all wells in a pool. Similarly, the average thickness-weighted water saturation using all wells in the pool is commonly assumed as the pool average water saturation.

### Drainage Area

Drainage area assignments to wells should be similar to offset analogous pools depending on the geological similarities and productivity of the wells within the analog. Pressure information is useful in estimating pool boundaries and if any potential barriers exist between wells. Seismic analysis usually improves the reservoir model and provides for more reliability in reserve or resource estimates.

### Formation Volume Factor

The volumetric calculation uses the initial oil or gas formation volume factor at the initial reservoir pressure and temperature. Both  $B_o$  and  $B_g$  are functions of fluid composition, reservoir pressure and

temperature and consequently of reservoir depth. The  $B_o$  and  $B_g$  values from analogous offset pools are often used as an initial estimate for the prospect under consideration.

### VOLUMETRIC UNCERTAINTY

A volumetric estimate provides a static measure of oil or gas in place. The accuracy of the estimate depends on the amount of data available, which is very limited in the early stages of exploration and increases as wells are drilled and the pool is developed. Article 8, entitled Monte Carlo Analysis, will present a methodology to quantify the uncertainty in the volumetric estimate based on assessing the uncertainty in input parameters such as:

- Gross rock volume – reservoir geometry and trapping
- Pore volume and permeability Distribution
- Fluid contacts

The accuracy of the reserve or resource estimates also increases once production data is obtained and performance type methods such as material balance and decline analysis can be utilized. Finally, integrating all the



techniques provides more reliable answers than relying solely on any one method.

#### REFERENCES

Aprilia, A. W., Li, Z., McVay, D. A. and Lee, W. J., SPE Gas Tech Symposium May 15-17 2006, Calgary. SPE Paper 100575-MS

Canadian Institute of Mining, Metallurgy and Petroleum, Determination of Oil and Gas Reserves, Petroleum Society Monograph Number I, 1994.

Etris, Ned and Stewart, Bruce. 2003. Net-to-gross ratio. CSPG Reservoir, v. 30, issue 4, p.24-25.

SPEE and CIM, Canadian Oil and Gas Evaluation Handbook, Vol 2. Detailed Guidelines for Estimation and Classification of Oil and Gas Resources and Reserves, November 2005.



# Reservoir Engineering for Geologists

## Article 4 - Production Decline Analysis

by Lisa Dean, P. Geol., and Ray Mireault, P. Eng., Fekete Associates Inc..

Production decline analysis is a basic tool for forecasting production from a well or well group once there is sufficient production to establish a decline trend as a function of time or cumulative production. The technique is more accurate than volumetric methods when sufficient data is available to establish a reliable trend and is applicable to both oil and gas wells.

Accordingly, production decline analysis is most applicable to producing pools with well established trends. It is most often used to estimate remaining recoverable reserves for corporate evaluations but it is also useful for waterflood and enhanced oil recovery (EOR) performance assessments and in identifying production issues/mechanical problems. Deviations from theoretical performance can help identify underperforming wells and areas and highlight where well workovers and/or changes in operating practices could enhance performance and increase recovery.

To the geologist, production decline analysis of an analogous producing pool provides a basis for forecasting production and ultimate recovery from an exploration prospect or stepout drilling location. A well's production capability declines as it is produced, mainly due to some combination of pressure depletion, displacement of another fluid (i.e., gas and/or water) and changes in relative fluid permeability. Plots of production rate versus production history (time or cumulative production) illustrate declining production rates as cumulative production increases (Figures 4.1 - 4.4).

In theory, production decline analysis is only applicable to individual wells but in practice extrapolations of group production trends often provide acceptable approximations for group performance. The estimated ultimate recovery (EUR) for a producing entity is obtained by extrapolating the trend to an economic production limit. The extrapolation is valid provided that::

- Past trend(s) were developed with the well producing at capacity.
- Volumetric expansion was the primary drive mechanism. The technique is not valid when there is significant pressure support from an underlying aquifer.

- The drive mechanism and operating practices continue into the future.

Production decline curves are a simple visual representation of a complex production process that can be quickly developed, particularly with today's software and production databases. Curves that can be used for production forecasting include:

- production rate versus time,
- production rate versus cumulative production,
- water cut percentage versus cumulative production,
- water level versus cumulative production,
- cumulative gas versus cumulative oil, and
- pressure versus cumulative production.

Decline curves a) and b) are the most common because the trend for wells producing from conventional reservoirs under primary production will be "exponential," in engineering jargon. In English, it means that the data will present a straight line trend when production rate vs. time is plotted on

a semi-logarithmic scale. The data will also present a straight line trend when production rate versus cumulative production is plotted on regular Cartesian coordinates. The well's ultimate production volume can be read directly from the plot by extrapolating the straight line trend to the production rate economic limit.

The rate versus time plot is commonly used to diagnose well and reservoir performance. Figure 4.1 presents a gas well with an exponential "straight line" trend for much of its production life. But in 2004 the actual performance is considerably below the expected exponential decline rate, indicating a non-reservoir problem. Wellbore modelling suggests that under the current operating conditions, the well cannot produce liquids to surface below a critical gas rate of about 700 Mscfd, which is about the rate when well performance started deviating from the expected exponential decline. Water vapour is probably condensing in the wellbore and impeding production from the well. Removing the water would restore the well's production rate to the exponential trend.

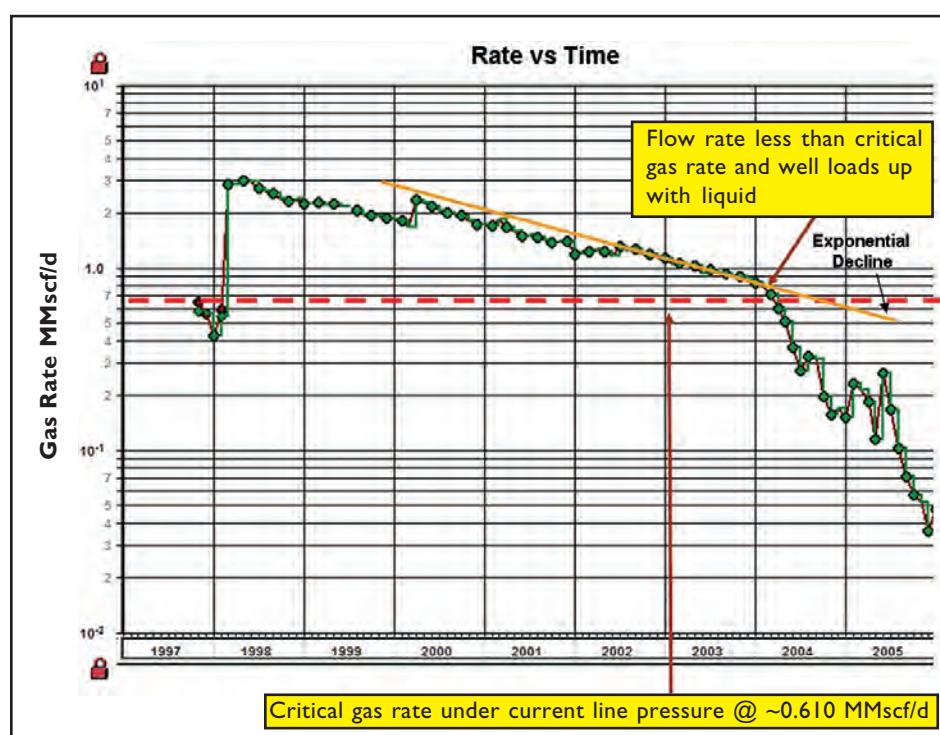


Figure 4.1. Gas well example showing liquid loading in the wellbore.

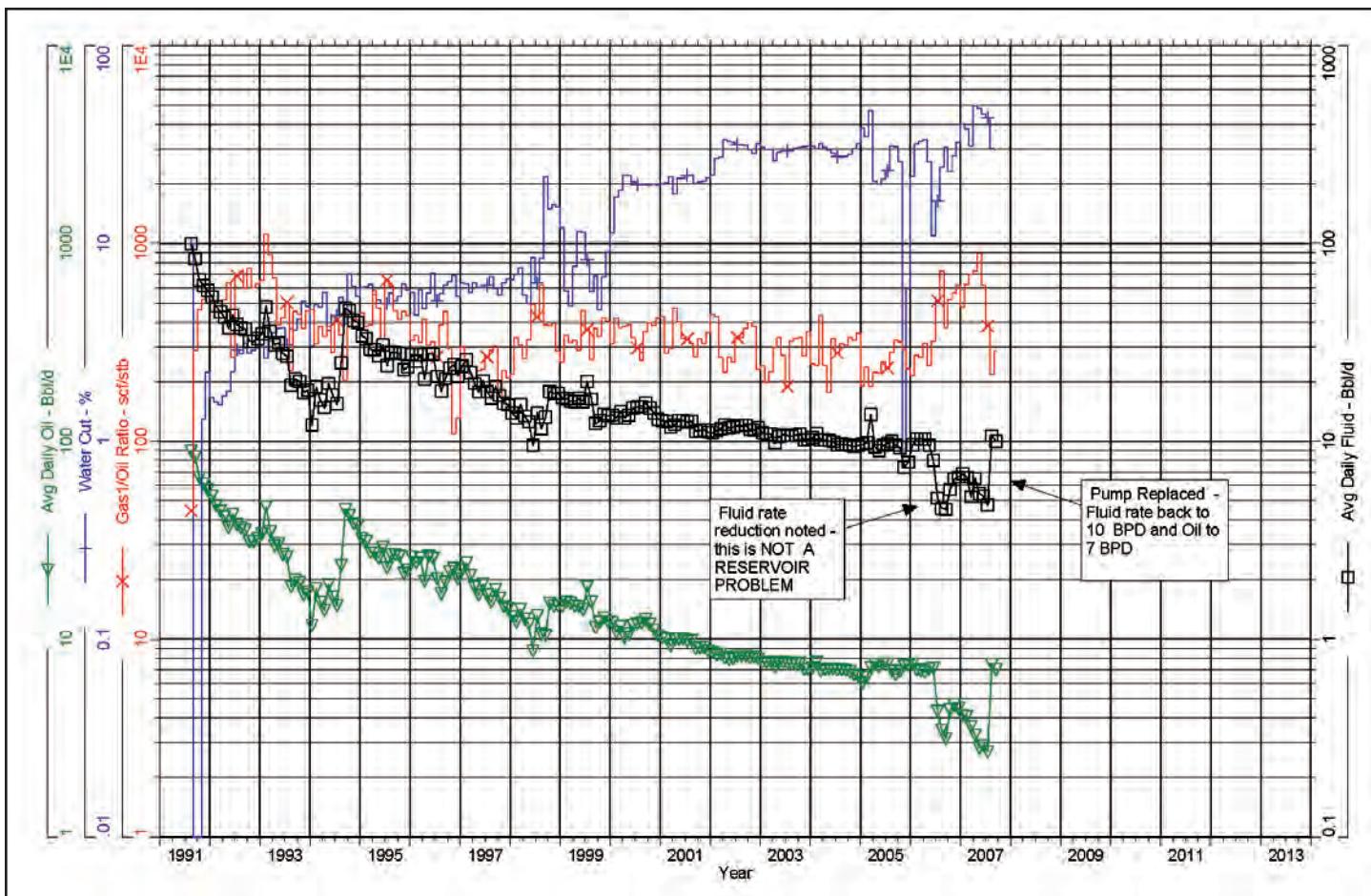


Figure 4.2. Pumping oil well where pump capability is decreasing.

Figure 4.2 is an example of a pumping oil well that encountered a pump problem. A rapid decline in production rate to below the exponential decline rate cannot be a reservoir issue and must therefore be due to equipment failure and/or near wellbore issues such as wax plugging or solids deposition in the perforations. In this case, the pump was replaced and the fluid rate returned to the value expected for exponential decline.

Arps (1945, 1956) developed the initial series of decline curve equations to model well performance. The equations were initially considered as empirical and were classified as exponential, hyperbolic, or harmonic, depending on the value of the exponent 'b' that characterizes the change in production decline rate with the rate of production (see Figure 4.3 and formulas at the end of the article). For exponential decline, 'b' = 0; for hyperbolic 'b' is generally between 0 and 1. Harmonic decline is a special case of hyperbolic decline where 'b' = 1.

The decline curve equations assume that reservoir rock and fluid properties (porosity, permeability, formation volume factor, viscosity, and saturation) governing the flow rate will not change with time or pressure.

While the assumption is not entirely correct, industry experience has proven that decline curves present a practical way to forecast well production in all but the most unusual circumstances.

Figure 4.3 illustrates the difference between

exponential, hyperbolic, and harmonic decline when production rate vs. cumulative production is plotted on Cartesian scales. The "straight" orange line extrapolates an exponential decline from the data. The green and blue lines present hyperbolic extrapolations of the data trend with 'b'

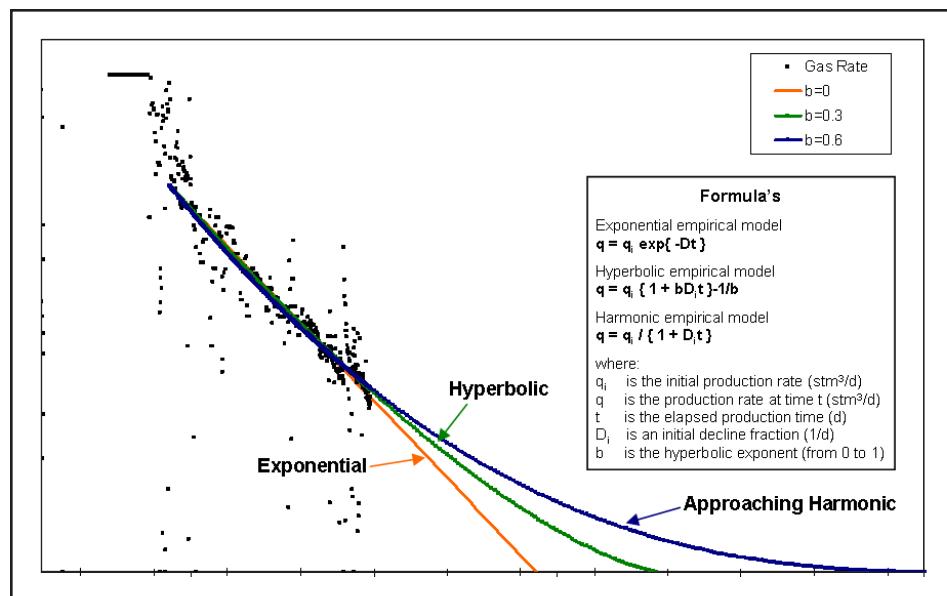


Figure 4.3. Production history rate versus cumulative production with associated decline formulas.

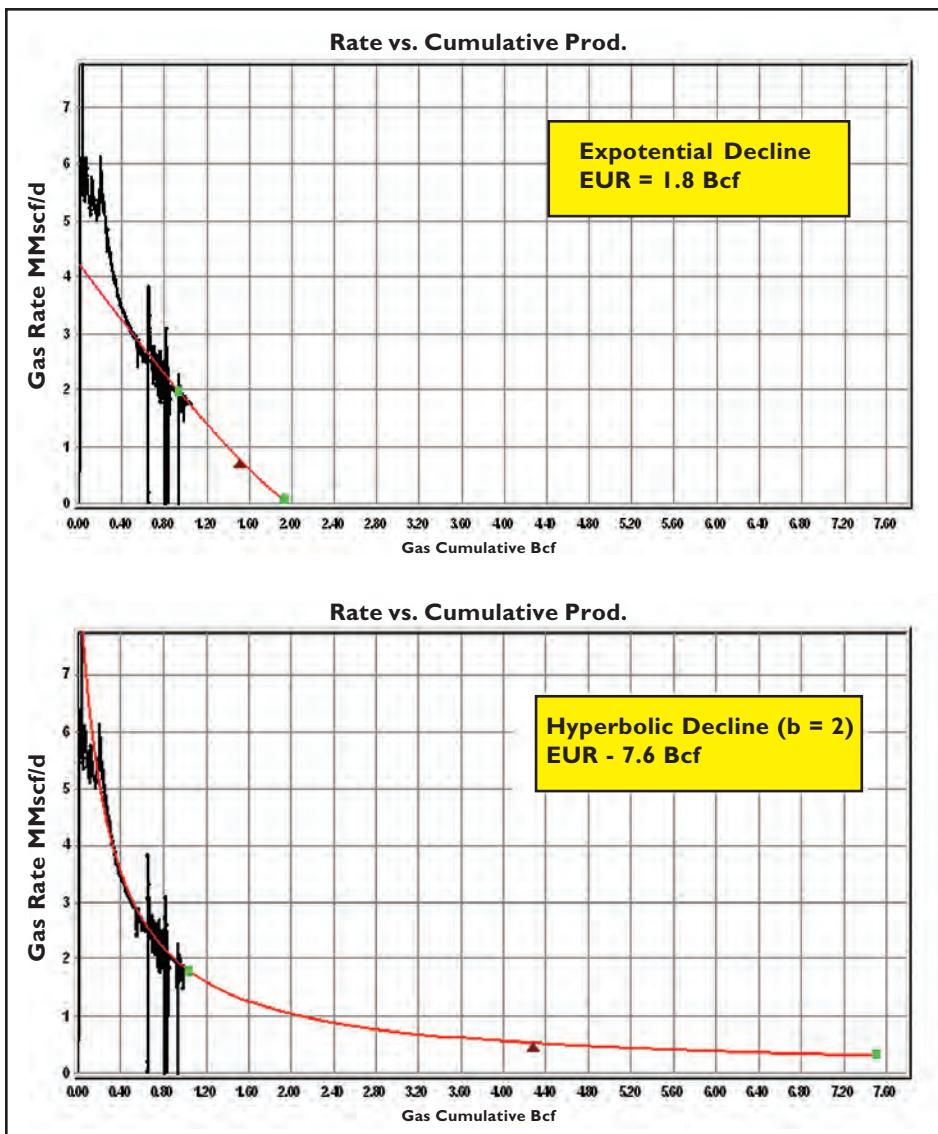


Figure 4.4.Tight gas well example illustrating minimum and maximum values for EUR depending in decline methodology.

values of 0.3 and 0.6, respectively. Note that the curvature of the line increases as the 'b' value increases.

Figure 4.3 also illustrates the main challenges in decline analysis – data scatter and the type of extrapolation that is appropriate for the well under consideration. Data scatter is an unavoidable consequence of dealing with real data. In western Canada, the permanent record of production and injection consists of monthly totals for gas, oil, and water production; operated hours; and wellhead pressure. For oil wells at least, monthly production at the battery is routinely prorated back to the individual wells, based on sequential 1-2 days tests of individual well capability. Depending on the number of wells and test capability at each battery, it can take up to several months to obtain a test on each well in the group.

Factors that determine the rate of decline

and whether declines are exponential, hyperbolic, or harmonic include rock and fluid properties, reservoir geometry, drive mechanisms, completion techniques, operating practices, and wellbore type. These factors must be understood prior to analyzing the production decline trends or serious errors in the ultimate production estimates can result (see Figure 4.4).

As stated previously, oil and gas wells producing conventional ( $>10$  md) permeability reservoirs under primary depletion (or fluid expansion) generally exhibit exponential decline trends. But the performance of some waterfloods and unconventional low permeability gas reservoirs are better modeled using hyperbolic decline trends.

Figure 4.4 presents an example of well production from a “tight” gas reservoir. These reservoirs are becoming increasingly

important to the industry but they typically have permeability below 0.1 md and are generally not productive without some form of mechanical fracture stimulation. From Figure 4a, a slightly hyperbolic (approximately exponential) extrapolation of the most recent production data yields an ultimate recovery of approximately 1.8 Bcf. But the hyperbolic decline trend of Figure 4b provides a good fit for the complete production history and indicates an ultimate recovery of 7.6 Bcf.

The typical range of 'b' values is approximately 0.3 to 0.8. A 'b' value of 2 represents an upper limit to the volume of gas that will ultimately be produced. The uncertainty in the trend that should be used to forecast well performance can be reflected in the assigned reserves as follows:

- Proven = 1.8 Bcf
- Proven + Probable + Possible = 7.6 Bcf

Based on the reserve definitions, the assignment suggests there is a 95% chance that the actual volume recovered will be greater than 1.8 Bcf and less than 7.6 Bcf. An estimate for the proven plus probable volume can be developed by integrating the well pressure history and material balance gas-in-place (OGIP) estimate with the decline analysis trend.

#### References

Arps, J. J. 1945. Analysis of Decline Curves. Trans. AIME, v. 160, p. 228-247.

Arps, J. J. 1956. Estimation of Primary Oil Reserves. Trans. AIME, v. 207, p. 182-191.

Canadian Institute of Mining, Metallurgy and Petroleum. 2004. Determination of Oil and Gas Reserves, Petroleum Society Monograph Number 1, Chapter 18.

Canadian Oil and Gas Evaluation Handbook. 2005. Volume 2, Detailed Guidelines for Estimation and Classification of Oil and Gas Resources and Reserves. Section 6: Procedures for Estimation and Classification of Reserves.

Stotts, W. J., Anderson, D. M., and Mattar, L. 2007. Evaluating and Developing Tight Gas Reserves – Best Practices. SPE paper # 108183 presented at the 2007 SPE Rocky Mountain Oil and Gas Technology Symposium, Denver, CO, USA, 16-18 April, 2007.

#### Formulas :

The Exponential decline equation is:  $q = q_i \exp\{-Dt\}$

where:

$q_i$  is the initial production rate ( $\text{stm}^3/\text{d}$ ),  
 $q$  is the production rate at time  $t$  ( $\text{stm}^3/\text{d}$ ),  
 $t$  is the elapsed production time ( $\text{d}$ ),  
 $D$  is an exponent or decline fraction ( $1/\text{d}$ ).

Solving for  $D$  and  $t$  gives:

$$D = -\ln \{ q/q_i \} / t \text{ and } t = -\ln \{ q/q_i \} / D$$

The cumulative production to time  $t$  ( $N_p$ ) is given by:

$$N_p = \int q dt = \int q_i \exp \{ -Dt \} dt = (q_i - q) / D$$

The Hyperbolic decline equation is:

$$q = q_i \{ 1 + bD_i t \}^{-1/b}$$

where:

$q_i$  is the initial production rate ( $\text{stm}^3/\text{d}$ ),  
 $q$  is the production rate at time  $t$  ( $\text{stm}^3/\text{d}$ ),  
 $t$  is the elapsed production time ( $\text{d}$ ),  
 $D_i$  is an initial decline fraction ( $1/\text{d}$ ),  
 $b$  is the hyperbolic exponent (from 0 to 1).

Solving for  $D_i$  and  $t$  gives:

$$D_i = [ (q_i/q)^b - 1 ] / bt \text{ and } t = [ (q_i/q)^b - 1 ] / D_i b$$

The cumulative production to time  $t$  ( $N_p$ ) is given by:

$$N_p = \int q dt = \int q_i \{ 1 + bD_i t \}^{-1/b} dt \\ = \{ q_i^b / [ (1 - b)D_i ] \} [ q^{1-b} - q^{1-b} ]$$

The Harmonic decline equation is:

$$q = q_i / \{ 1 + D_i t \}$$

where:

$q_i$  is the initial production rate ( $\text{stm}^3/\text{d}$ ),  
 $q$  is the production rate at time  $t$  ( $\text{stm}^3/\text{d}$ ),  
 $t$  is the elapsed production time ( $\text{d}$ ),  
 $D_i$  is an initial decline fraction ( $1/\text{d}$ ).

Solving for  $D_i$  and  $t$  gives:

$$D_i = [ (q_i/q) - 1 ] / t \text{ and } t = [ (q_i/q)^{-1} ] / D_i$$

The cumulative production to time  $t$  ( $N_p$ ) is given by:

$$N_p = \int q dt = \int q_i \{ 1 + D_i t \}^{-1} dt \\ = \{ q_i / D_i \} \ln \{ q_i / q \}$$



# Reservoir Engineering for Geologists

## Article 5 – Material Balance Analysis

by Ray Mireault, P. Eng., and Lisa Dean, P. Geol., Fekete Associates Inc..

With sufficient production, material balance techniques offer an alternative, largely independent, method of estimating the original hydrocarbons in-place (OOIP and OGIP) to supplement the direct volumetric calculation. A material balance of a pool's history can also help to identify the drive mechanism and the expected recovery factor range, since different drive mechanisms display different pressure behaviours for the same cumulative production. Figure 5.1 presents the different P/Z curve trends that result from different drive mechanisms.

Material balance calculations are commonly used to answer reservoir development questions but the technique can also help with the interpretation of reservoir geometry. Geological and geophysical mapping will give an indication of a pool's shape and orientation but typically the confidence in the in-place volume is not high unless the well and/or seismic control is abundant. Conversely, material balance can reveal a great deal about the volume of a reservoir but nothing about its shape or orientation. The combination of the two often greatly improves the understanding and interpretation of the pool parameters.

Material balance uses actual reservoir performance data and therefore is generally accepted as the most accurate procedure for estimating original gas in place. In general, a minimum of 10 to 20% of the in-place volume must be produced before there is sufficient data to identify a trend and reliably extrapolate to the original in-place volume through material balance. Thus material balance is of direct use to the development geologist who is attempting to identify infill and step-out drilling locations to optimize the depletion of a pool. To the explorationist, material balance is probably most often used to describe the production behaviour of analogous producing pools.

The material balance procedure describes the expansion of oil, gas, water, and rock over time as a pool is produced. When fluid is removed from a reservoir, reservoir pressure tends to decrease and the remaining fluids expand to fill the original space. Injection situations, such as waterflooding or gas storage, are handled by treating the injection volumes as negative production.

The material balance equation is simply an inventory of the mass of all materials

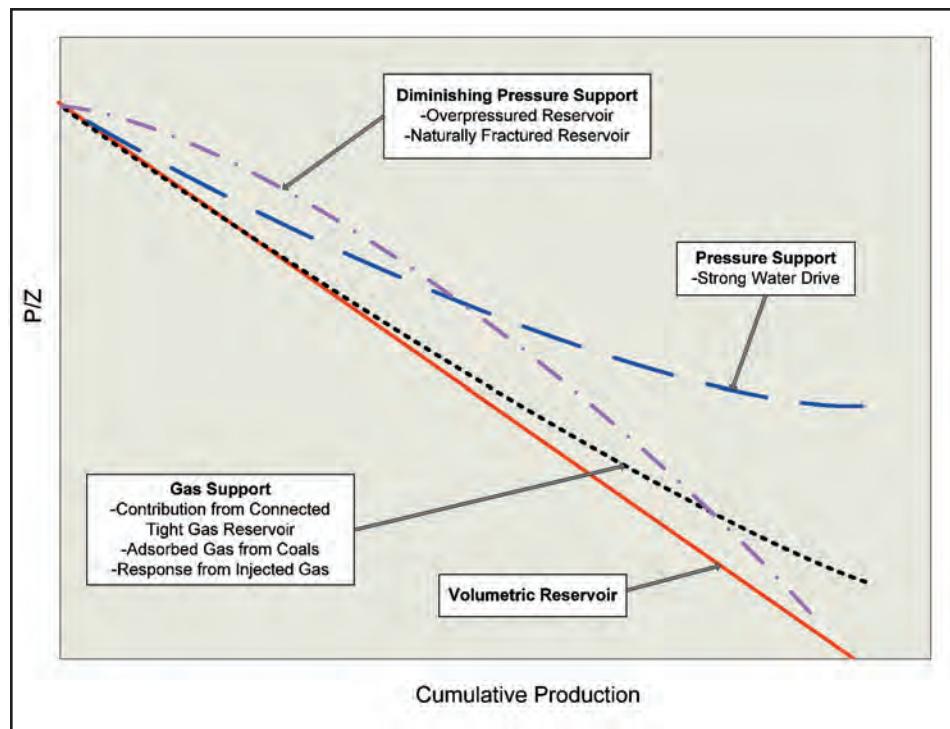


Figure 5.1. Gas reservoir P/Z material balance diagnostics.

entering, exiting, and accumulating in the reservoir. For the sake of convenience, this mass balance is usually expressed in terms of reservoir voidage (see CIM Monograph I, page 143 for the general material balance equation). In theory, the original in-place volume can be determined knowing only:

- Oil, gas, water, and rock compressibility.
- Oil formation volume factor ( $B_o$ ) and solution gas ratio ( $R_s$ ) at the pressures considered.
- The amount of free gas in the reservoir at initial reservoir pressure.
- Connate water saturation.
- Production/injection volumes and the associated reservoir pressures.

In practice, the material balance calculation is quite complex and its application requires several simplifying assumptions, including:

- A constant reservoir temperature is assumed despite changes in reservoir pressure and volume. For most cases the approximation is acceptable, as the relatively large mass and heat conduction capability of reservoir rock plus the relatively slow changes

in pressure create only small variations in reservoir temperature over the reservoir area.

- A constant reservoir volume assumes that changes in the pore space of the rock with pressure depletion are so small that they can be ignored. The assumption is valid only when there is a very large contrast between reservoir rock compressibility and the compressibility of the contained fluids.

Typical compressibility ranges are:

- Rock:  $0.2 \text{ to } 1.5 \times 10^{-6} \text{ kPa}^{-1}$
- Gas:  $10^{-3} \text{ to } 10^{-5} \text{ kPa}^{-1}$  (Varies significantly with reservoir pressure.)
- Water:  $0.2 \text{ to } 0.6 \times 10^{-6} \text{ kPa}^{-1}$
- Oil:  $0.4 \text{ to } 3 \times 10^{-6} \text{ kPa}^{-1}$

Thus rock compressibility can be ignored in normally pressured or volumetric gas reservoirs (see Figure 5.1) and oil reservoirs with free gas saturation. Ignoring rock compressibility in over-pressured reservoirs and in fluid systems that do not have a gas phase will overestimate the original in-place



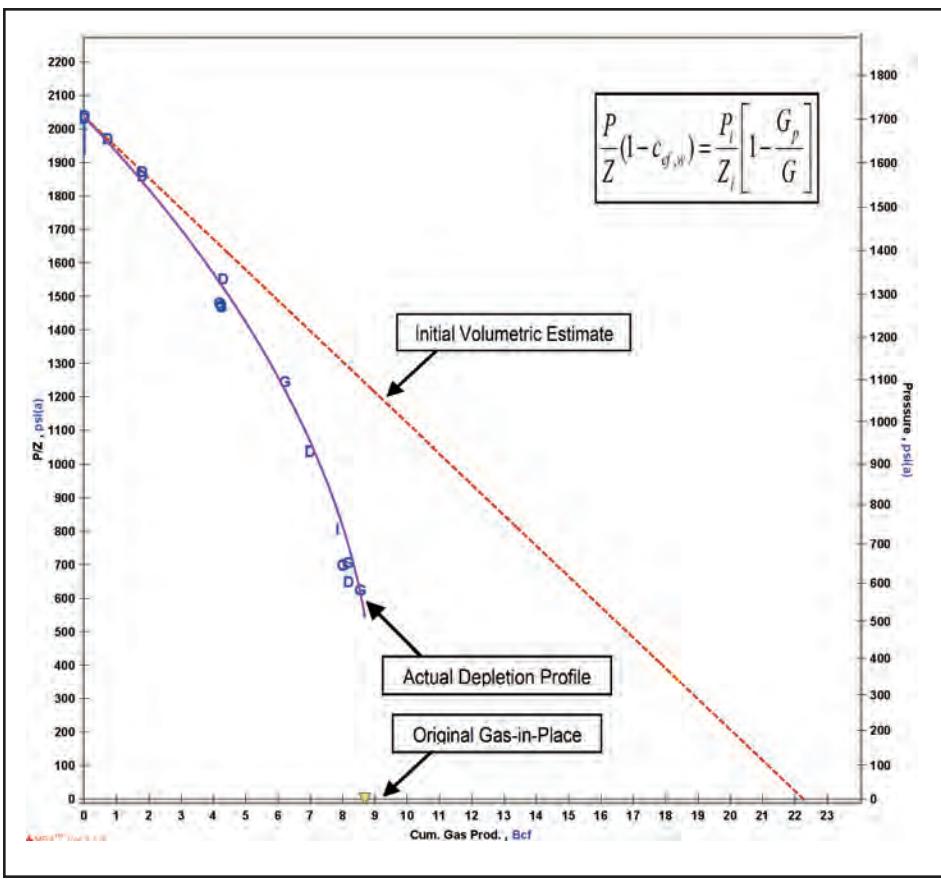


Figure 5.2. Multi-well gas reservoir P/Z plot.

hydrocarbons (see Figure 5.2).

- Representative pressure / volume / temperature (PVT) data for the oil, gas and water in the reservoir. Usually, the challenge is to obtain a representative oil sample for laboratory analysis. Bottomhole sampling can inadvertently lower the sampling pressure and cause gas to come out of solution. Surface sampling requires accurate measurements of oil and gas production during the test to correctly recombine the produced streams. Gas reservoir sampling requires accurate measurement of the gas and condensate production and compositional analysis to determine the composition and properties of the reservoir effluent.
- Accurate and reliable production data directly impacts the accuracy of the in-place estimate. Produced volumes of oil (and gas if it's being sold) are generally accurate because product sales meters at the oil battery and gas plant are kept in good repair. Prorationing of the monthly sales volumes back through the gathering system(s) to the individual wells is standard industry practice. It introduces a level of uncertainty in the reported production values for the wells that can generally be tolerated,

provided the prorationing is performed in accordance with industry standards.

- A uniform pressure across the pool is assumed because the properties of the reservoir fluids are all related to pressure. In practice, average reservoir

pressures at discrete points in time are estimated from analyses of well pressure build-up tests (we'll talk about well tests in another article). Although local pressure variations near wellbores can be ignored, pressure trends across a pool must be accounted for. The additional uncertainty in the pressure estimate introduces another challenge to the hydrocarbon in-place calculations but is generally tolerable.

A material balance can be performed for a single well reservoir (or flux unit) or a group of wells that are all producing from a common reservoir / flux unit. However, well production and pressure information is commonly organized into "pools" or subsurface accumulations of oil or gas by regulatory agencies, on the basis of the initially available geological information. The "pool" classification does not account for internal compartmentalization so a single pool can contain multiple compartments/reservoirs/flux units that are not in pressure communication with each other. To further confuse the issue, the word "reservoir" is often used interchangeably with the word "pool" and is also used to refer to the "reservoir" rock regardless of fluid content. For clarification, in this series of articles "reservoir" means an individual, hydraulically isolated compartment within a pool.

Thus the first real world challenge to a reliable material balance is identifying which portions of the off-trend data scatter are due to measurement uncertainty, pressure gradients across the reservoir, and different

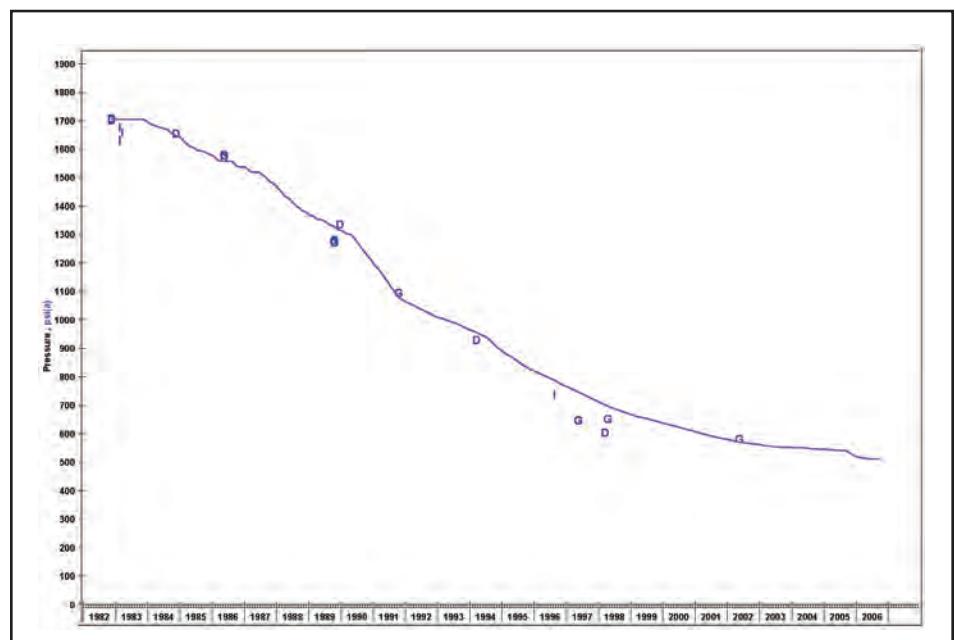


Figure 5.3. Multi-well gas reservoir pressure vs. time plot.

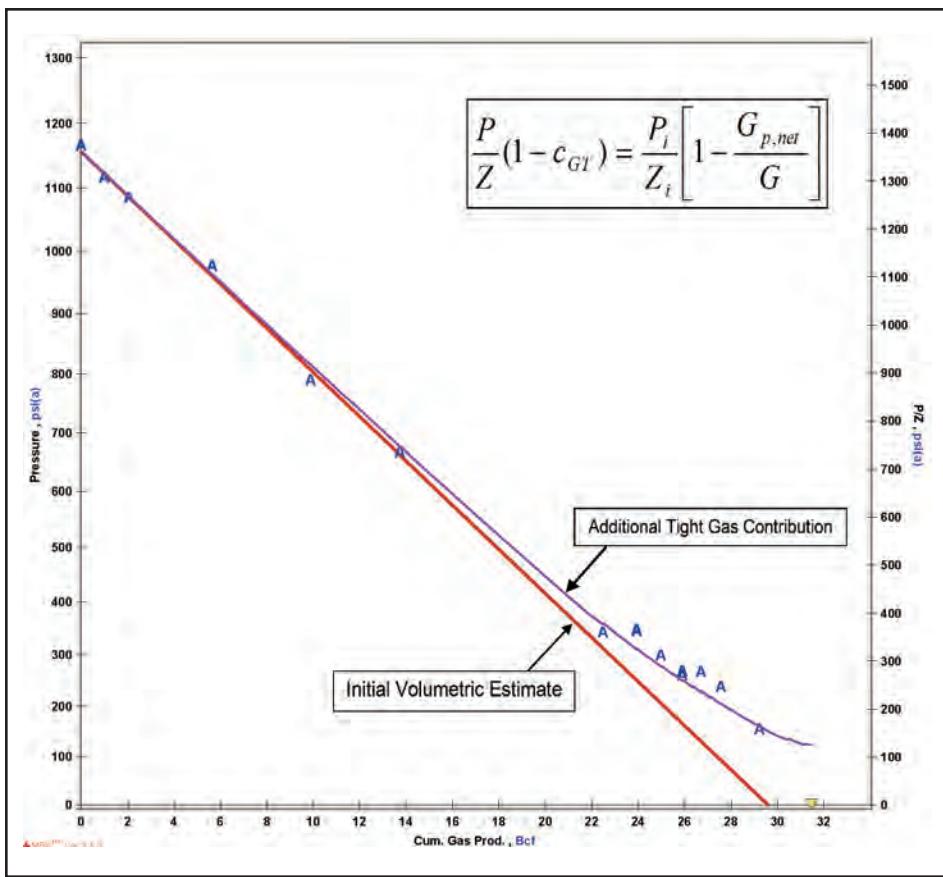


Figure 5.4. Single well gas reservoir P/Z plot.

pressure trends over time due to reservoir compartmentalization. For gas reservoirs (oil reservoirs will be discussed in next month's Reservoir), a pressure vs. time plot (see Figure 5.3) greatly assists in the diagnosis as follows:

- The accuracy of electronic pressure gauges has dramatically reduced the uncertainty in the interpreted reservoir pressure due to gauge error. It can cause small random variations in the interpreted pressures but the magnitude is so small that it is seldom a factor when a pressure deviates from the trend line on a P/Z plot.
- Inadequate build-up times during pressure tests lead to interpreted reservoir pressures at the well that are always less than true reservoir pressure.
- Pressure gradients across a reservoir are always oriented from the wells with the greatest production to wells with little or no production.
- The failure to separate and correctly group wells into common reservoirs is the most common reason for excessive data scatter. Wells producing from different reservoir compartments

within a common pool will each have their own pressure/time trend that can be identified with adequate production history and used to properly group the wells.

For confidence in the original-gas-in-place estimate of Figure 5.2, Figure 5.3 compares a computer-predicted "average" reservoir pressure, based on the combined production history of the grouped wells and the interpreted gas-in-place volume of Figure 5.2, with the interpreted reservoir pressures from well pressure build-up tests. All pressure measurements follow the predicted trend, which indicates that the wells have been correctly grouped into a common reservoir.

Well pressures that fall below the trend line of Figure 5.3 are consistent with a production-induced pressure gradient across the reservoir (well G and I) and/or an inadequate build-up time during pressure testing (wells D and G). For the occasional anomalous reservoir pressure in a series that otherwise follows the trend, other circumstances may justify a detailed review of selected well build-up tests and their interpretation. The horizon(s) tested, the reservoir geometry, formation permeability and depth variations across the reservoir, the type of test (static gradient, wellhead,

flow, and buildup), the length of the test (shut-in time for buildups), the temperature gradient in the reservoir, and the accuracy of the fluid composition all contribute to the accuracy of the reservoir pressure interpretation.

The classical P/Z plot for normally pressured gas reservoirs is perhaps the simplest form of the material balance equation and so it is introduced first. Rock and water expansion can be ignored because of the high gas compressibility. Assuming an isothermal or constant temperature reservoir and rearranging terms yields the equation in the form of a straight line  $y = b - mx$  as follows:

$$P / Z = (P_i / Z_i) - Q * (P_i / (G_i * Z_i))$$

Where:

$P$  = the current reservoir pressure  
 $Z$  = the gas deviation from an ideal gas at current reservoir pressure  
 $P_i$  = the initial reservoir pressure  
 $Z_i$  = the gas deviation from an ideal gas at initial reservoir pressure  
 $Q$  = cumulative production from the reservoir  
 $G$  = the original gas-in-place

As the equation and Figures 5.1 and 5.2 indicate, when there is no production, current reservoir pressure is the initial reservoir pressure. When all the gas has been produced, reservoir pressure is zero and cumulative production equals the initial gas-in-place volume.

A straight line on the P/Z plot is common in medium and high (10 to 1,000 mD) permeability reservoirs. A strong upward curvature that develops into a horizontal line, as presented in Figure 5.1, demonstrates pressure support in the reservoir and is usually associated with a strong water drive. Formation compaction can cause a non-linear, downward trend, as in the example of Figure 5.2. However, a downward trend may also be caused by unaccounted-for well production from the reservoir.

A slight upward curvature in the P/Z plot indicates some gas influx into the main reservoir from adjacent tight rock as illustrated by Figure 5.1 and the single well reservoir of Figure 5.4. The upward curvature illustrates that there is a significant permeability difference between the main reservoir and the adjacent rock. A limited upward curvature on P/Z plots is being observed with increasing frequency in Alberta as medium and high permeability reservoirs are produced to depletion and the industry develops lower and lower permeability plays.

## References

Canadian Institute of Mining, Metallurgy and Petroleum, 2004. Determination of Oil and Gas Reserves. Petroleum Society Monograph Number 1, Chapter 7.

Canadian Institute of Mining, Metallurgy and Petroleum, 2005. Canadian Oil and Gas Evaluation Handbook, Volume 2, Detailed Guidelines for Estimation and Classification of Oil and Gas Resources and Reserves. Section 6: Procedures for Estimation and Classification of Reserves.

Cosentino, Luca, 2001. Integrated Reservoir Studies. Gulf Publishing Company. Chapters 5-6.

Mattar, L. and Anderson, D, 2005. Dynamic Material Balance (Oil or Gas-in-place without Shut-ins). SPE paper # 2005-113, presented at the 2005 Canadian International Petroleum Conference, Calgary, AB, Canada, 7-9 June 2005.

Mattar, L. and McNeil, R, 1998. The “Flowing” Gas Material Balance. Journal of Canadian Petroleum Technology, Volume 37, No. 2, Pages 52-55.

Rahman, Anisur N.M., Anderson, D., and Matter, L., 2006. New, Rigorous Material Balance Equation for Gas Flow in a Compressible Formation with Residual Fluid Saturation. SPE Paper #100563, presented at the 2006 SPE Gas Technology Symposium, Calgary, AB., 15-17 May 2006.

---



# Reservoir Engineering for Geologists

## Article 6 - Material Balance for Oil Reservoirs

by Ray Mireault, P. Eng.; Chris Kupchenko, E.I.T; and Lisa Dean, P. Geol., Fekete Associates Inc.

Material balance calculations for oil reservoirs are more complex than for gas reservoirs. They must account for the reservoir volumes of the produced fluids and the effect of pressure depletion on the oil volume remaining in the reservoir. They must account for the formation, expansion, and production of solution gas. The calculations must also account for the expansion of the reservoir rock and formation water, since they have similar compressibility as oil. As noted in last month's article, typical compressibility ranges are:

- Rock:  $0.2$  to  $1.5 \times 10^{-6} \text{ kPa}^{-1}$
- Gas:  $10^{-3}$  to  $10^{-5} \text{ kPa}^{-1}$  (Varies significantly with reservoir pressure.)
- Water:  $0.2$  to  $0.6 \times 10^{-6} \text{ kPa}^{-1}$
- Oil:  $0.4$  to  $3 \times 10^{-6} \text{ kPa}^{-1}$

Nonetheless, in theory, material balance calculations can provide an independent estimate for the original oil-in-place for a solution gas drive reservoir with sufficient production history.

Havlena and Odeh (1963) developed a useful graphical procedure for estimating the oil-in-place volume for a solution gas drive reservoir (see Figure 6.1). By rearranging the material balance equation so that the total withdrawals from the reservoir are grouped onto the y axis while all the expansion terms are grouped on the x axis, the correct oil-in-place value will generate a straight line trend on the graph. Thus the oil volume for a solution gas drive reservoir can be determined by successively iterating until a straight line is achieved. Upward curvature indicates that the value selected as the OOIP is too small. Downward curvature indicates that the selected value is larger than the true size of the oil deposit. Various formulations of the material balance equation can be sourced in any of the references cited.

Figure 6.2 presents a Havlena-Odeh plot for a solution gas drive reservoir with an OOIP of 49 MMSTB. The four points calculated from reservoir pressure measurements are in good agreement with the predicted trend based on the OOIP value. Inadequate pressure buildup time may be the reason that the third pressure measurement comes in slightly below the predicted trend line.

When an oil deposit has a gas cap, the

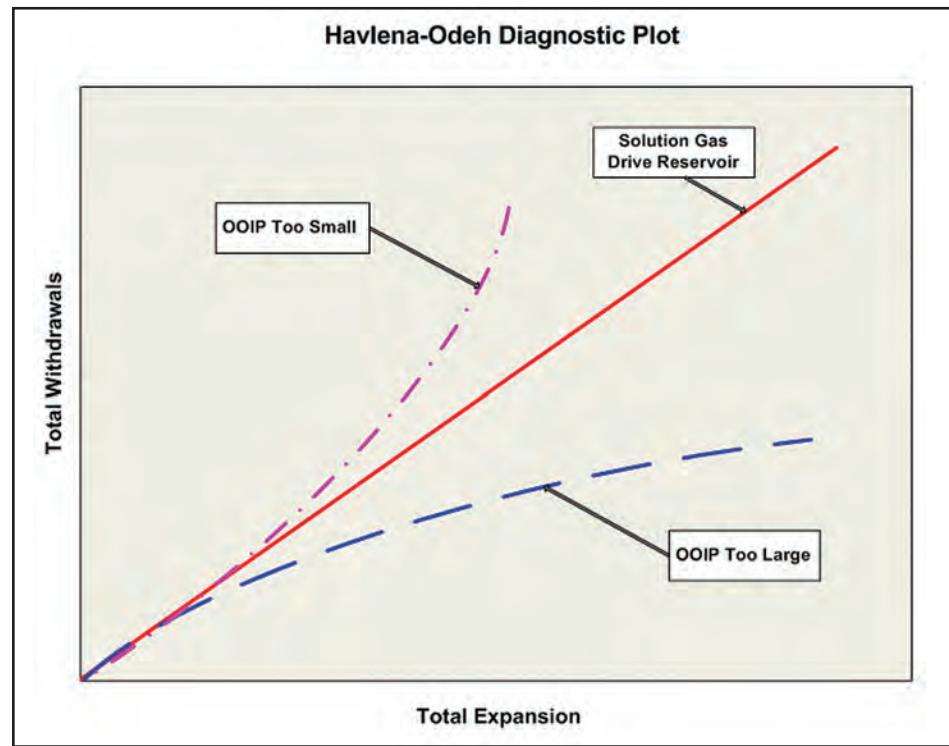


Figure 6.1. Gas reservoir P/Z material balance diagnostics.

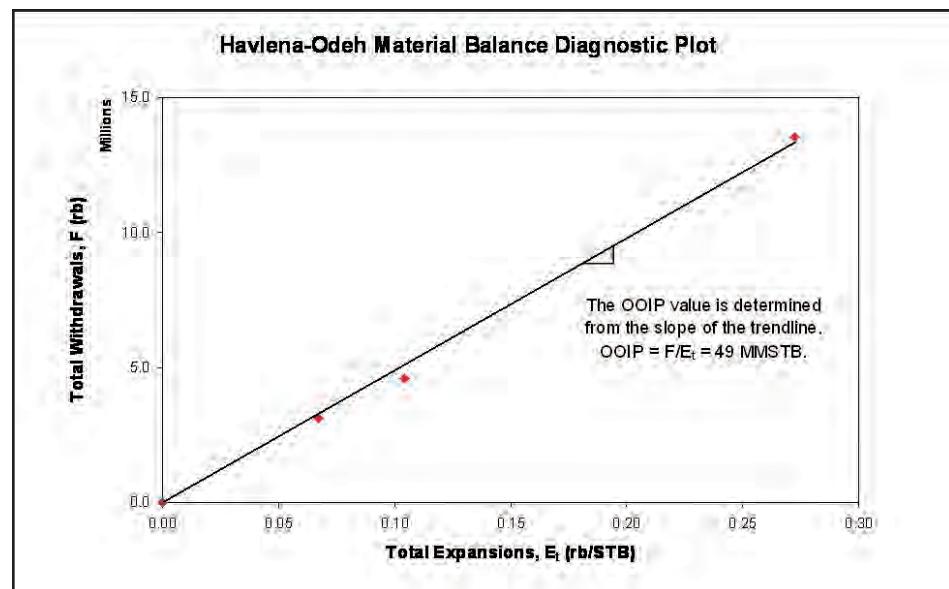


Figure 6.2. Multi-well gas reservoir P/Z plot.

material balance calculations must also account for gas cap expansion and production. However, there are now too many unknowns to develop a unique solution by material balance alone. Estimating the oil-in-place in the presence of a gas cap first requires a volumetric estimate for the size

of the gas cap. Then the size of the oil deposit can be estimated via material balance calculations.

Though it cannot independently determine the oil-in-place volume when a gas cap is present, the Havlena-Odeh plot can assist in

### Havlena-Odeh Diagnostic Plot

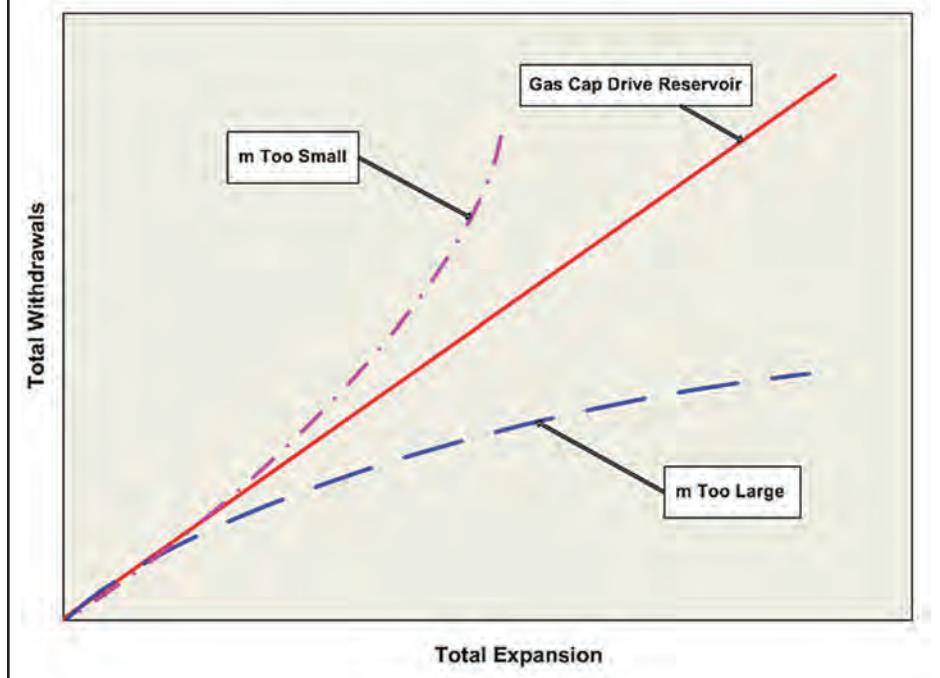


Figure 6.3. Multi-well gas reservoir pressure vs. time plot.

confirming the consistency of the proposed solution. For every gas cap volume, there will be a corresponding oil-in-place volume that together result in a straight line pressure trend on the Havlena-Odeh plot. As before, upward curvature on the plot indicates that the OOIP value is too small; downward curvature that it is too large (Figure 6.3).

In practice, a table of values for OOIP is often set up and iteration performed on the ratio of the reservoir volume of the gas cap relative to the oil-inplace (referred to as "m"). Now upward curvature on the Havlena-Odeh plot indicates that the "m" value (size of the gas cap) is too small relative to the selected oil volume. Downward curvature indicates that "m" (size of the gas cap) is too large (Figure 6.3).

Due to the fact the solution is non-unique many combinations of OOIP and "m" can be found that will mathematically match the reservoir production and pressure history. Mathematically successful solutions can range from:

- A large oil volume with a relatively small gas cap.
- A small oil volume with a relatively large gas cap.
- Multiple intermediate oil and gas cap volume combinations.

The dilemma can usually be resolved by using

geological knowledge to identify the material balance solution(s) consistent with the reservoir's physical geometry. This consistency check provides the best chance of determining the correct magnitude of OOIP and OGIP.

Geologic knowledge of the reservoir geometry is also essential when attempting to assess fluid influx into a reservoir. For example, water influx into a D-3 reef with an underlying aquifer could be assessed by periodically logging selected wellbores to determine and relate a rising oil-water interface to a water influx volume. Once the influx volume is estimated, in theory a material balance estimate for the original oil-in-place volume can be calculated. However, internal compartmentalization of the reef into multiple reservoirs may make the task significantly more challenging than might be concluded from this article.

The Havlena-Odeh plot is also useful when fluid influx is suspected, as in possible inflow across a fault. In theory, measured reservoir pressures on a Havlena-Odeh plot will exhibit (Figure 6.4):

- A straight line for a volumetric (solution gas or gas cap) expansion reservoir provided the OOIP and OGIP values are correct.
- An upward curvature when there is pressure support due to fluid influx.

- A downward curvature when there is a pressure deficit.

The Havlena-Odeh plot cannot however, identify the reason for pressure support or the pressure deficit. Potential reasons for pressure support include:

- An unaccounted-for water injection/disposal scheme.
- Flow from a deeper interval via a fault or across a fault from an adjacent reservoir compartment. Note that the fluid can be any combination of oil, gas, and water.
- "U tube" displacement of the producing reservoir's water leg by a connected reservoir. The connected reservoir is usually gas-bearing and may be undiscovered.
- Expansion of water. Due to the limited compressibility of water ( $0.2$  to  $0.6 \times 10^{-6}$  kPa $^{-1}$ ) the water volume must be at least 10 times the reservoir oil volume for water expansion to provide pressure support. Thus the Cooking Lake aquifer underlying Alberta D-3 oil pools has the potential but water legs in clastic reservoirs are too small.

Potential reasons for a pressure deficit or downward curvature include:

- Later time interference from unaccounted-for producing wells.
- Rock compressibility in an overpressured reservoir.
- An inflow that gradually decreases over time, perhaps because of depletion or because flow across the fault decreases/ceases below a certain pressure threshold.

In cases where fluid inflow is suspected, knowledge of the reservoir geometry is an absolute requirement to limit the possible reasons for either an upward or downward curving trend.

Thus far, the discussion has been on the theoretical challenges to material balance analysis. In addition, a real world challenge is the scatter that is present in the pressure data. As with gas systems, oil well pressure data must first be correctly grouped into common reservoirs to generate reliable trends. But oil pressure data generally exhibits greater scatter because:

- Longer build-up times are required to



extrapolate the pressure data to a reliable estimate of reservoir pressure, due to the increased viscosity of oil

- Pressure gradients across the reservoir are more pronounced, due to the oil viscosity.
- Pressure differences in an oil column, due to the density of the oil, are sufficient to require careful correction to a common datum.
- Multiple perforation intervals and inadvertent commingling of intervals that were isolated by nature creates the potential for crossflow and further confuses the pressure data interpretation.

Other potential sources of error include:

- Thermodynamic equilibrium is not attained.
- PVT data that does not represent reservoir conditions.
- Uncertainty in the "m" ratio.
- Inaccurate production allocation.

Yet despite the foregoing theoretical and practical challenges, material balance analysis has proven its worth, with the accuracy of the analysis generally increasing as the reservoir is produced. In Fekete's experience, the most reliable analyses are obtained by integrating the reservoir geology; fluid properties; and the well production, pressure, and completion histories into a consistent explanation.

#### References

Canadian Institute of Mining, Metallurgy and Petroleum, 2004. Determination of Oil and Gas Reserves. Petroleum Society Monograph Number 1, Chapter 7.

Havlena, D., and Odeh, A.S. 1963. The Material Balance as an Equation of a Straight Line. Trans., AIME, Vol. 228, p. 896.

Canadian Oil and Gas Evaluation Handbook, 2005. Procedures for Estimation and Classification of Reserves, Vol 2, Section 6.

Craft, B.C., and Hawkins, M.F., 1964. Applied Petroleum Reservoir Engineering. Prentice Hall Inc., Englewood Cliffs, NJ.

Canadian Institute of Mining, Metallurgy and Petroleum, 2004. Determination of Oil and Gas Reserves. Petroleum Society Monograph Number 1, Chapter 7.

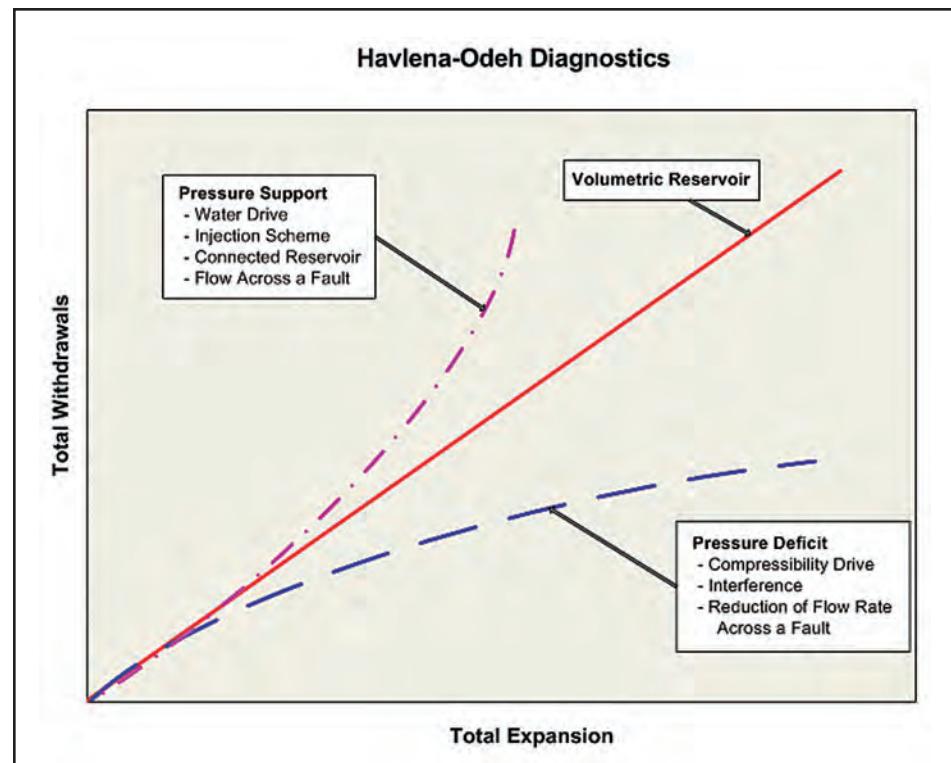


Figure 6.4. Single well gas reservoir P/Z plot.

Canadian Institute of Mining, Metallurgy and Petroleum, 2005. Canadian Oil and Gas Evaluation Handbook, Volume 2, Detailed Guidelines for Estimation and Classification of Oil and Gas Resources and Reserves. Section 6: Procedures for Estimation and Classification of Reserves.

Cosentino, Luca, 2001. Integrated Reservoir Studies. Gulf Publishing Company. Chapters 5-6. Mattar, L. and Anderson, D., 2005. Dynamic Material Balance (Oil or Gas-in-place without Shut-ins). SPE paper # 2005-113, presented at the 2005 Canadian International Petroleum Conference, Calgary, AB, Canada, 7-9 June 2005.

Mattar, L. and McNeil, R., 1998. The "Flowing" Gas Material Balance. Journal of Canadian Petroleum Technology, Volume 37, No. 2, Pages 52-55.

Rahman, Anisur N.M., Anderson, D., and Matter, L., 2006. New, Rigorous Material Balance Equation for Gas Flow in a Compressible Formation with Residual Fluid Saturation. SPE Paper #100563, presented at the 2006 SPE Gas Technology Symposium, Calgary, AB., 15-17 May 2006.

Aprilia, A.W., Li, Z., McVay, D.A. & Lee, W.J., SPE Gas Tech Symposium May 15-17 2006, Calgary. SPE Paper 100575-MS

Canadian Institute of Mining, Metallurgy and Petroleum, Determination of Oil and Gas

Reserves, Petroleum Society Monograph Number 1, 1994.

SPEE and CIM, Canadian Oil and Gas Evaluation Handbook, Vol 2. Detailed Guidelines for Estimation and Classification of Oil and Gas Resources and Reserves, November 2005.



# Reservoir Engineering For Geologists

## Article 7 – Well Test Interpretation

by Louis Mattar, P. Eng. and Lisa Dean, P. Geol., Fekete Associates Inc.

Let's start off with a simple situation:

- Well A produces at 100 bopd from a reservoir that contains 1 millions barrels of oil.
- Well B also produces at 100 bopd from a reservoir that also contains 1 millions barrels of oil.

Are these two wells worth the same?

The answer is NO. This is because Well A is in a high permeability reservoir, but has a zone of reduced permeability around the wellbore (damage caused by drilling mud filtrate invasion or clay swelling). If this well were to be stimulated its rate would increase significantly. On the other hand, Well B is in a low permeability reservoir, which is the factor that limits its production rate.

How can we identify the differences between these two wells? The answer is well testing.

Well testing, often called pressure transient analysis (PTA), is a powerful tool for reservoir characterization. The following information can be extracted from well tests:

- Permeability – The value obtained from a well test is much more useful than that from core analysis, because it represents the in-situ, effective permeability averaged over a large distance (tens or hundreds of metres).
- Skin (damage or stimulation) – Most wells are either damaged or stimulated, and this has a direct effect on the deliverability of the well. The skin is a measure of the completion effectiveness of a well. A positive skin (typically +1 to +20) represents damage, while a negative skin (typically -1 to -6) represents improvement.
- Average reservoir pressure – This parameter, which is either measured directly or extrapolated from well test data, is used in material balance calculations for determining hydrocarbons-in-place.
- Deliverability potential – The IPR (inflow performance relationship) or the AOF (absolute open flow) is used in forecasting a well's production.

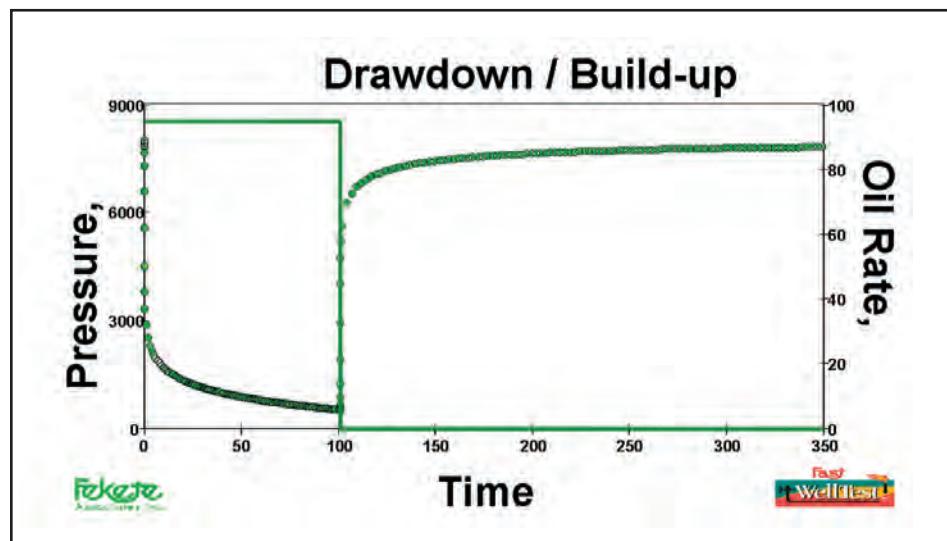


Figure 7.1. Drawdown and build-up test.

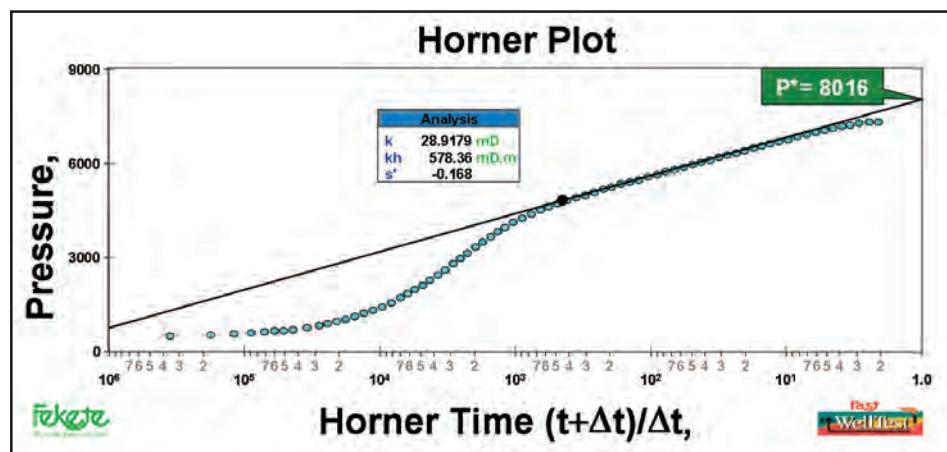


Figure 7.2. Semi-log (Horner) plot of build-up data.

- Reservoir description – Reservoir shape, continuity, and heterogeneity can be determined from pressure transient tests
- Fluid samples – The reservoir fluid composition and its PVT (pressure-volume-temperature) properties can have a significant effect on the economics and production operations.
- Well testing is also an integral part of good reservoir management and fulfills government regulations.
- FUNDAMENTALS:
  - A well test is a measurement of flow rate, pressure, and time, under controlled conditions. While the well is flowing, the quality of the data is often poor, thus the data during a shut-in is usually analyzed.
  - Opening or closing a well creates a pressure pulse. This "transient" expands with time, and the radius investigated during a test increases as the square root of time. The longer the flow test, the further into the reservoir we investigate.
  - Because of the diffusive nature of pressure transients, any values determined from a well test represent area averages and not localized point values.
  - The analysis of oil well tests is similar



to that of gas well tests. The theory is derived in terms of liquid flow, and is adapted for use with gas by converting pressure to "pseudo-pressure ( $\psi$ )" and time to "pseudo-time( $t_a$ )."

- The practice of testing a flowing oil well and a gas well is similar – measure the bottom-hole pressure. However, for a pumping oil well, it is often not easy to measure the bottom-hole pressure directly, so it is usually calculated from surface data and Acoustic Well Sounders, thereby having a greater potential for error. This article will concentrate on the analysis of the two most common well test types in Alberta, namely "build-up" and "deliverability" tests.

#### • Build-up test\*:

To conduct a build-up test, simply shut the well in. It is obvious that a build-up test must be preceded by one or more flow periods. Figure 1 shows the simplest possible build-up, a shut-in that follows a single constant rate. In practice, the period preceding the buildup will often consist of variable rates, and even multiple flows and shut-ins. These non-constant flow periods cannot be ignored, but must be accounted for during the analysis. This is done through a mathematical process called superposition, which converts these variable flow periods into an equivalent constant rate.

#### • Deliverability tests:

The purpose of these tests is to determine the long term deliverability of a well, rather than defining the permeability and skin (as in build-up tests). There is one overriding factor in these tests; it is that at least one of the flow durations must be long enough to investigate the whole reservoir. This condition is known as "stabilized" flow. Sometimes it is impractical to flow a well for that long. In that case, the stabilized condition is calculated from the reservoir characteristics obtained in a build-up test.

#### INTERPRETATION:

Interpretation of well test data is often conducted in two stages. The first is a diagnostic analysis of the data to reveal the reservoir model and the second is modeling of the test.

#### DATA PREPARATION:

To analyze the build-up data, it is transformed into various coordinate systems in order to accentuate different characteristics. The most

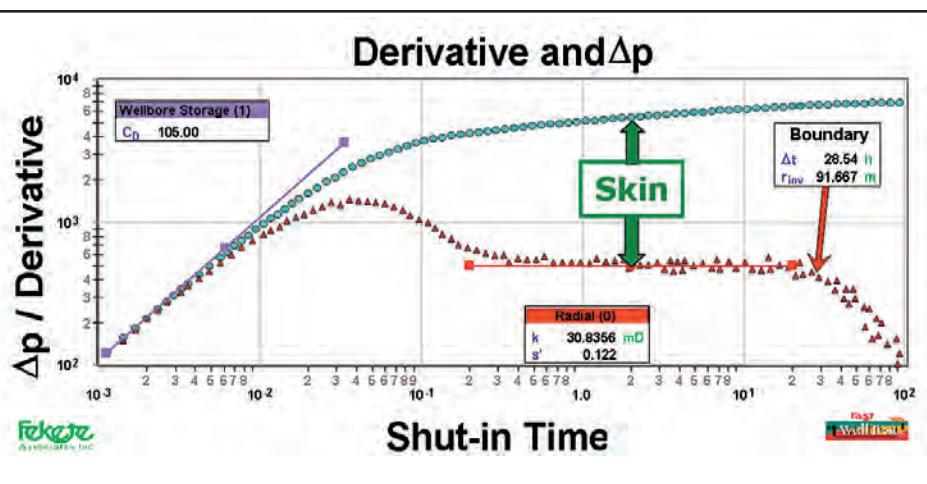


Figure 7.3. Derivative plot of build-up data.

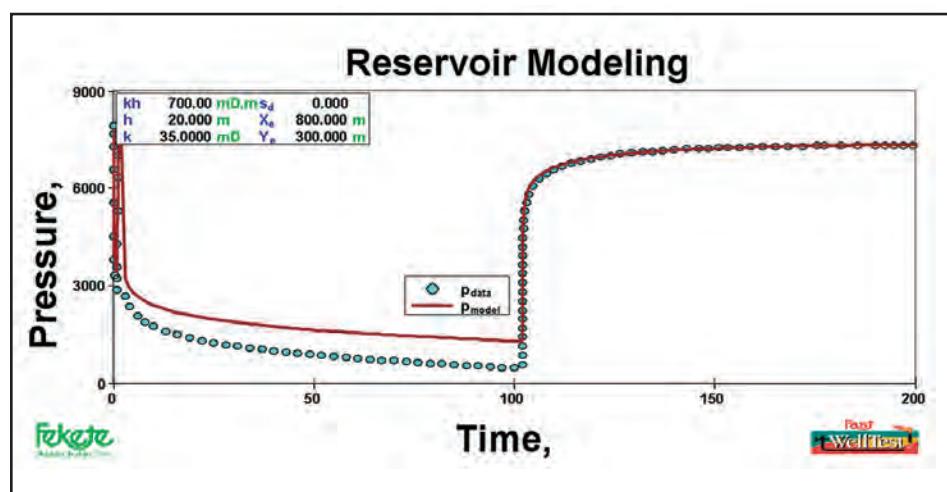


Figure 7.4. Modeling comparison of synthetic and measured pressures.

useful transformation is the "derivative" plot, obtained as follows:

- Plot the shut-in pressure,  $p$  (for gas\*,  $\psi$ ) versus  $\log \{ (t + \Delta t) / \Delta t \}$ , where  $t$  is the duration of the flow period (or the corresponding superposition time, when the flow period has not been constant) and  $\Delta t$  is the shut-in time. A semi-log plot of this is called a Horner plot and is shown in Figure 7.2.
- Determine the slope of the Horner plot at each  $\Delta t$ . This slope is called the derivative.
- Plot the derivative versus  $\Delta t$  on log-log graph paper (Figure 7.3).
- Calculate  $\Delta p$  (for gas\*,  $\Delta\psi$ ), the difference between the build-up and the last flowing pressure.

- On the same log-log graph as the derivative, plot  $\Delta p$  (for gas,  $\Delta\psi$ ) versus  $\Delta t$  (Figure 7.3).

#### DIAGNOSTIC ANALYSIS:

The buildup is divided into three time regions – early, middle, and late time. The middle time represents radial flow, and it is not until middle time is reached that the permeability can be determined. In Figure 7.2, the permeability is calculated from the slope of the semi-log straight line, and in Figure 7.3, from the vertical location of the flat portion of the derivative. These two answers should be the same.

The skin is calculated from the  $\Delta p$  curve. In Figure 7.3, the larger the separation between the curves in the middle time region, the more positive is the skin.

Early time represents the wellbore and the nearwellbore properties (effects of damage, acidizing, or hydraulic fracture). It is often associated with a (log-log) straight line of fixed slope. A slope equal to "one" means

\*Injection and fall-off tests are analyzed the same way as a build-up – simply replace the production rate by the injection rate, and the pressure rise by the pressure fall.

\*In well testing the corrections caused by pseudo-time are usually negligible. For simplicity this article will use "t" rather than "ta".



## Modified Isochronal Test

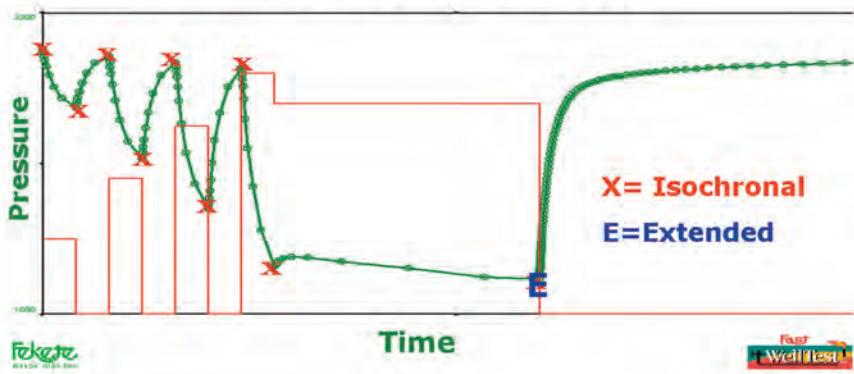


Figure 7.5. Modified isochronal test.

the test (Figure 7.4). The values of the parameters in the model (permeability, skin, distances to boundaries, etc.) are varied until an acceptable match is obtained between the synthetic and measured pressures.

This process, called modeling or history matching, is a powerful mathematical tool, but must be used with caution, as it can result in mathematically correct, but physically meaningless answers. Some very complex reservoirs (multi-layers, heterogeneous, etc.) can be modeled using sophisticated mathematical models, but for these interpretations to be meaningful, they must be consistent with known geological descriptions and realistic physical well completions.

### TYPES OF WELL TESTS:

- RFT\*, WFT\*, MDT\*, RCI\*, FRT\* – These are tests of very short duration (minutes) conducted on a wireline, usually while the well is drilling. The popular use is for determining the reservoir pressure at various depths.
- DST (drill stem test) – conducted during drilling of exploratory wells, to determine reservoir fluids, reservoir pressure and permeability. Onshore DSTs are usually open hole, whereas offshore DSTs are cased hole. An open-hole DST typically consists of a 5-minute pre-flow and a 30-minute build-up. It is analyzed exactly like the build-up test described above. Because of the short flow durations,  $p^*$  does equal  $p_r$ . It should be noted that on most “scout tickets” what is reported is not  $p^*$  or  $p_r$ , but the ISI (initial shut-in pressure) and the FSI (final shut-in pressure). In low permeability reservoirs, the FSI is usually less than the ISI, and sometimes this difference is misconstrued as being caused by depletion occurring during the test (which implies a small reservoir and could lead to abandonment of that zone).
- Build-up – The well is shut-in, following one or more flow periods. The pressure is measured and analyzed to give permeability, skin, average reservoir pressure, and reservoir description. This is the most commonly analyzed test because it is often quite long (several days of flow and several days of shut-in) and the data quality is usually good.
- Interference or pulse – These tests involve flowing one well (active) but measuring the pressure at another well

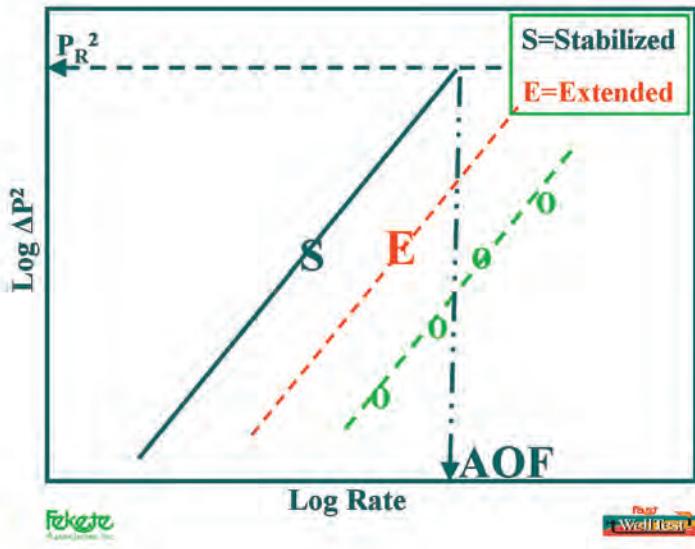


Figure 7.6.AOF plot.

“wellbore storage,” and during that period, nothing can be learned about the reservoir because the wellbore is still filling up. A slope of “half” typically means linear flow as a result of a hydraulic fracture. From this straight line, the fracture length or fracture effectiveness can be calculated if the permeability is known.

The period after middle time is known as late time, and it reflects the effect of the reservoir boundaries and heterogeneities. It is from this region that the reservoir shape can be determined. A straight line slope approximately “half” would indicate a long, narrow reservoir. A straight line slope approximately “one” could imply a low permeability reservoir surrounding the region investigated during middle time. If the derivative trends downward during the late time period, it could indicate an improvement in permeability (actually mobility) away from the well. If this downward curvature is

severe, it might be indicative of a depleting reservoir.

The average reservoir pressure ( $p_r$ ) is obtained by extrapolating the semi-log straight line to infinite shut-in time ( $=1$  on the Horner plot). This extrapolation is called  $p^*$  and it is used, along with an assumed reservoir shape and size, to calculate the average reservoir pressure. For short flow durations, for example in a DST or in the initial test of a well, the correction from  $p^*$  to  $p_r$  is negligible, and  $p^*$  does equal  $p_r$ .

### MODELING:

Once the analysis has been completed and an approximate reservoir description deduced, a mathematical model of the reservoir is constructed. This model utilizes the production history of the test (all the flow and shut-in data) to generate “synthetic” pressures which are then compared with the pressures that were actually measured during

\*Trade Marks: RFT=Repeat Formation Tester, WFT=Wireline Formation Tester, MDT=Modular Dynamic Tester, RCI= Reservoir Characterization Instrument, FRT=Flow Rate Tester

(observation), and are used to determine interwell connectivity.

- IPR – These tests are designed to yield the long-term deliverability of the well, and are not concerned with determining the reservoir characteristics. The deliverability test for an oil well is called IPR (inflow performance relationship). It describes the inflow into the wellbore at various bottom-hole pressures. The test consists of a single flow until stabilization is reached, at which time the oil and water flow rates and the flowing pressure are measured. An IPR is plotted according to known relationships such as the Vogel IPR equation.

• AOF (absolute open flow) – An AOF test is the gas well equivalent to a liquid IPR test. It too must have at least one flow rate to stabilization. It differs from a liquid IPR in several ways:

- Often more than one flow rate is required. This is because gas flow in the reservoir can be turbulent (liquid flow is laminar) and the degree of turbulence can be assessed only by utilizing multiple flow rates.

The governing equation is not Vogel's but a "Back-Pressure Equation" of the form  $q = C (\Delta p^2)^n$ , where  $q$  is the flow rate,  $C$  a constant that depends on the well's characteristics (permeability, skin, etc.) and  $n$  is a measure of turbulence. Values of  $n$  range from 1 to 0.5, where  $n = 1$  means laminar flow and  $n = 0.5$  means fully turbulent flow.

- $P^2$  is used instead of pseudo-pressure as a simplification.
- Typically four different flow rates are selected (e.g., four hours each) with a 4-hour intervening shut-in. These are called the isochronal points. If the time to stabilization is too long, then the "stabilized" rate is replaced by an "extended" flow (3 to 5 days). The results of the build-up analysis are used to calculate what the stabilized flow rate and pressure would have been.

A best-fit straight line is drawn through the isochronal data on a log-log plot of  $\Delta p^2$  versus  $q$ . A line parallel to that is drawn through the stabilized point (NOT the extended point) (Figure 7.6). This is the stabilized deliverability line and is used for determining the flow rate that corresponds to any specified back-pressure. Extrapolating this line to  $P_R^2$  gives the maximum deliverability potential of the well (when the

back-pressure is zero,  $\Delta p^2 = P_R^2$ ). This maximum is called the AOF (absolute open flow) and is one of the most commonly used indicators of the well's deliverability potential.

- PITA (perforation inflow test analysis) – In these tests, sometimes referred to as PID (perforation inflow diagnostic), the well is perforated and the pressure rise in the closed wellbore is recorded, and interpreted to yield an estimate of permeability and reservoir pressure. These tests are useful for "tight gas" where most other tests would take too long because of the very low permeability.

## REFERENCES

Energy Resources Conservation Board. 1979. Gas Well Testing – Theory and Practice. ERCB, Guide G3 (Directive 034), 547 p.

Lee, J., Rollins, J.B., and Spivey, J.P. 2003. Pressure Transient Testing. Society of Petroleum Engineers, v. 9, 376 p.



# Reservoir Engineering for Geologists

## Article 8 – Rate Transient Analysis

by Louis Mattar, P. Eng., Ray Mireault, P. Eng., and Lisa Dean, P. Geol., Fekete Associates Inc..

While a well is producing, a lot of information can be deduced about the well or the reservoir without having to shut it in for a well test. Analysis of production data can give us significant information in several areas:

**1. Reserves** – This is an estimate of the recoverable hydrocarbons, and is usually determined by traditional production decline analysis methods, as described in Article #4 in this series (Dean, L. and Mireault, R., 2008).

**2. Reservoir Characteristics** – Permeability, well completion efficiency (skin), and some reservoir characteristics can be obtained from production data by methods of analysis that are extensions of well testing (Mattar, L. and Dean, L., 2008)

**3. Oil- or Gas-In-Place** – The modern methods of production data analysis

(Rate Transient Analysis) can give the Original- Oil-In-Place (OOIP) or Original-Gas-In- Place (OGIP), if the flowing pressure is known in addition to the flow rate.

The principles and methods discussed in this article are equally applicable to oil and gas reservoirs, but – for brevity – will only be presented in terms of gas.

### TRADITIONAL METHODS : RESERVES

From an economic perspective, it is not what is in the reservoir that is important, but rather what is recoverable. The industry term for this recoverable gas is “Reserves.” There are several ways of predicting reserves. One of these methods, traditional decline analysis (exponential, hyperbolic, harmonic) has already been discussed in Article #4. The method is used daily for forecasting production and for economic evaluations. Generally, the results are meaningful, but they can sometimes be unrealistic (optimistic or

pessimistic), as will be illustrated by the following examples.

Example 1, shown in Figure 8.1, clearly exhibits an exponential decline. It is obvious from this Figure that the recoverable reserves are 2.9 Bcf. Typically this type of gas well has a recovery factor of 80% (0.8), and one can thereby conclude that the originalgas- in-place (OGIP) =  $2.9/0.8 = 3.6$  Bcf. By using the modern rate transient analysis described later in this article, it will be shown that this value of OGIP is grossly pessimistic.

Example 2, (Figure 8.2, page 30), also exhibits an exponential decline. It can be seen from this Figure that the recoverable reserves are 10 Bcf. Assuming a recovery factor of 80% (0.8), the OGIP =  $10/0.8 = 12.5$  Bcf. By using the modern rate transient analysis described later in this article, it will be shown that this value of OGIP is optimistic.

Example 3, (Figure 8.3, page 30) is a tight gas

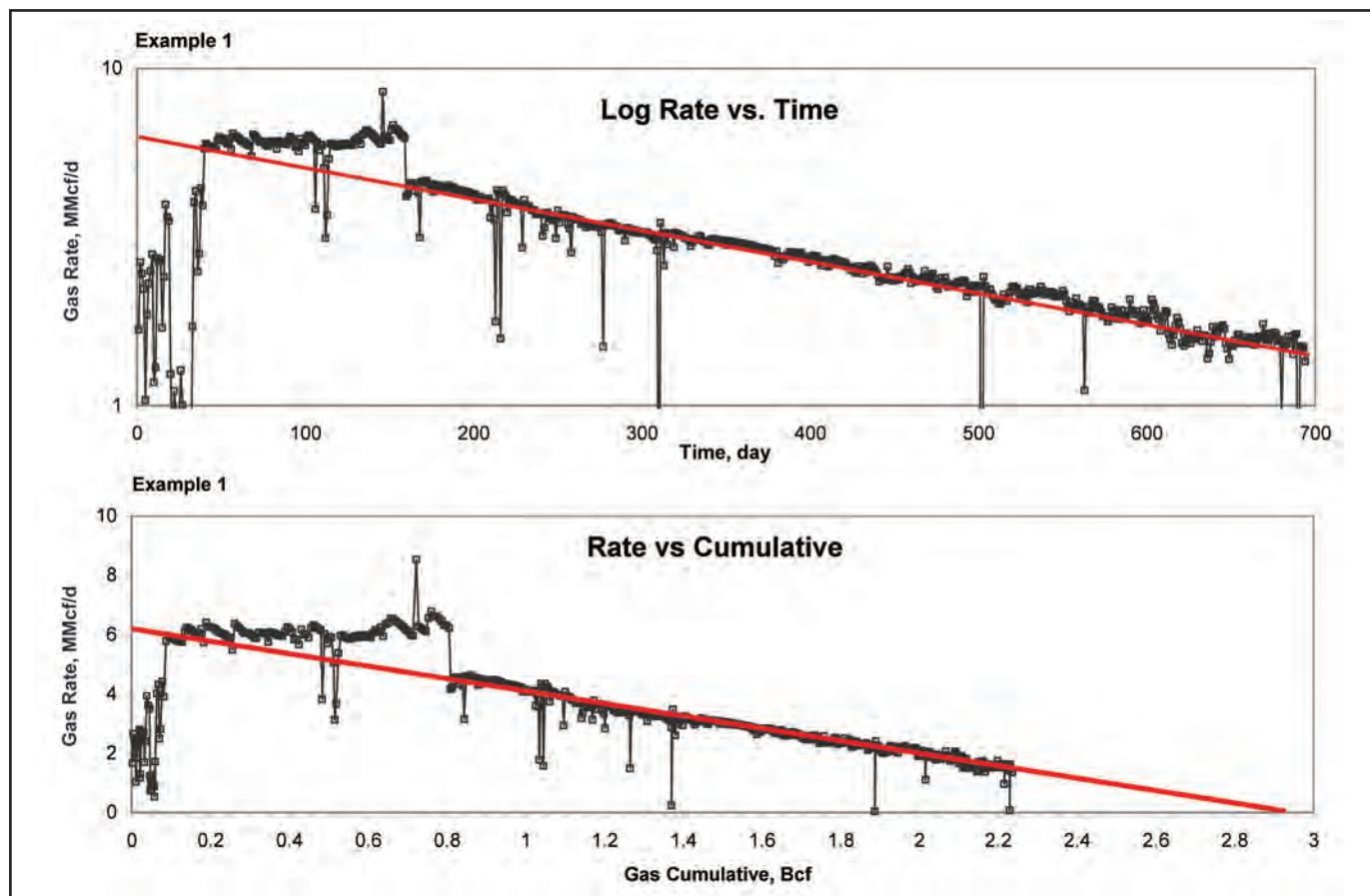


Figure 8.1.Traditional decline - example 1.



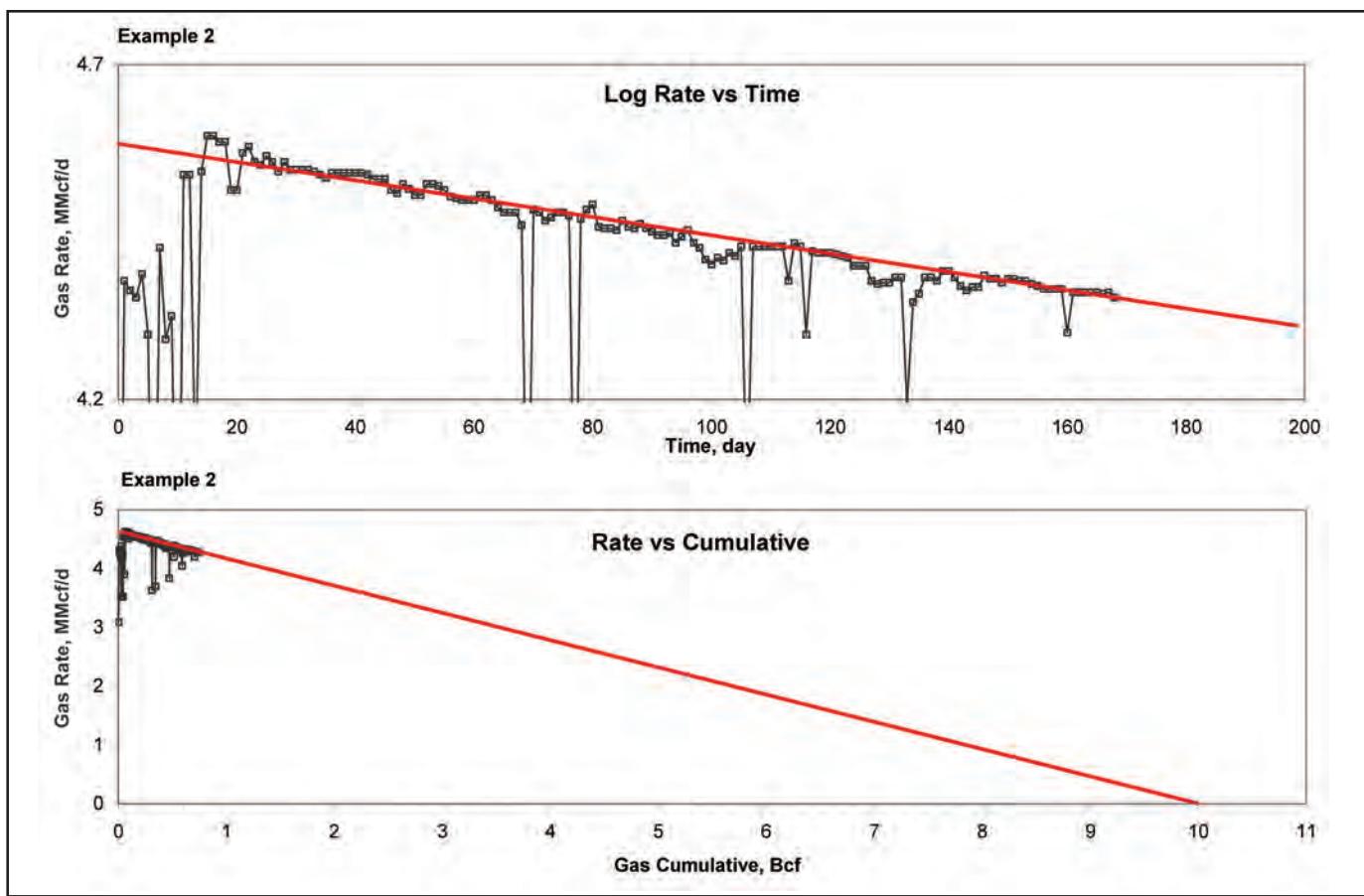


Figure 8.2.Traditional decline - example 2.

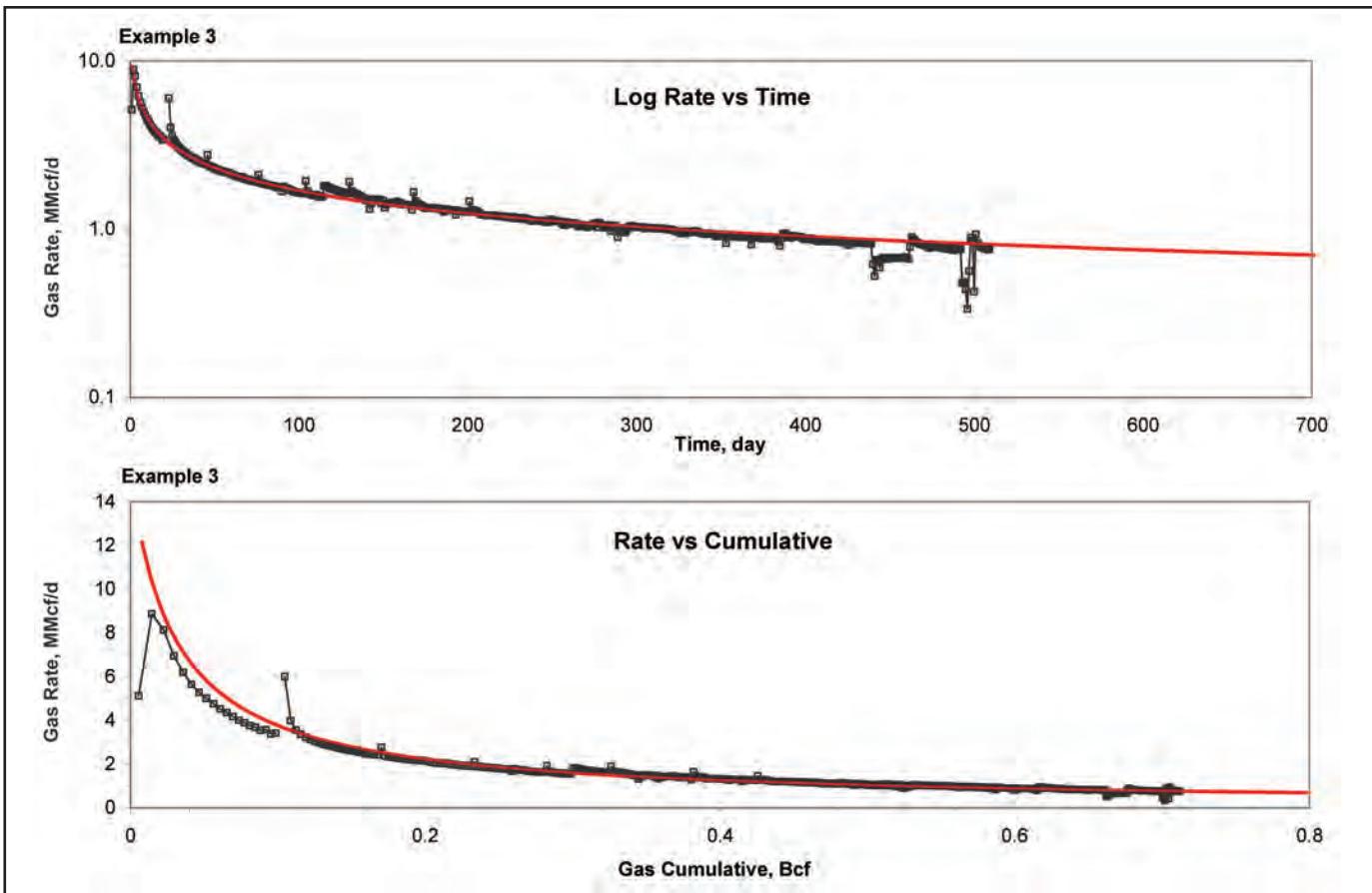


Figure 8.3.Traditional decline - example 3.

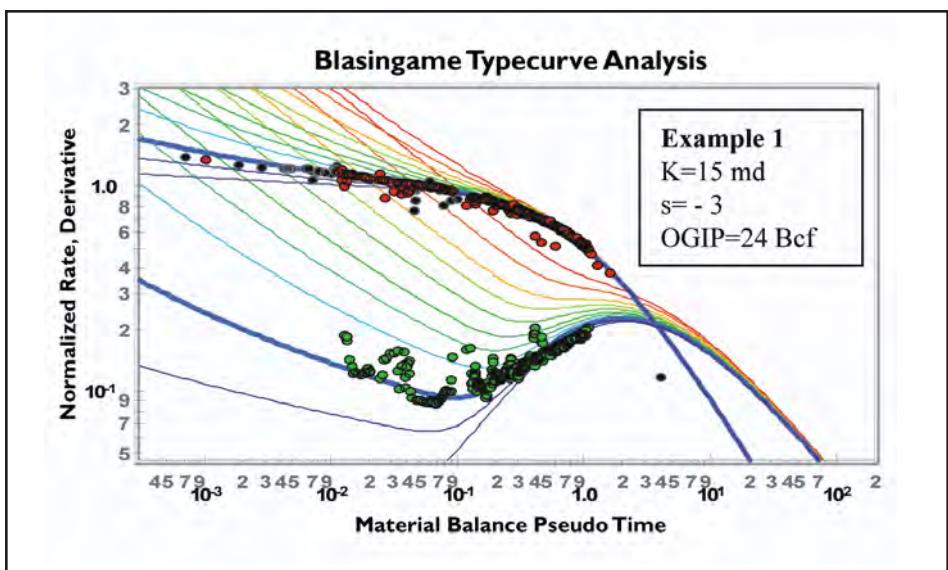


Figure 8.4. Rate transient analysis - type curve match - example 1.

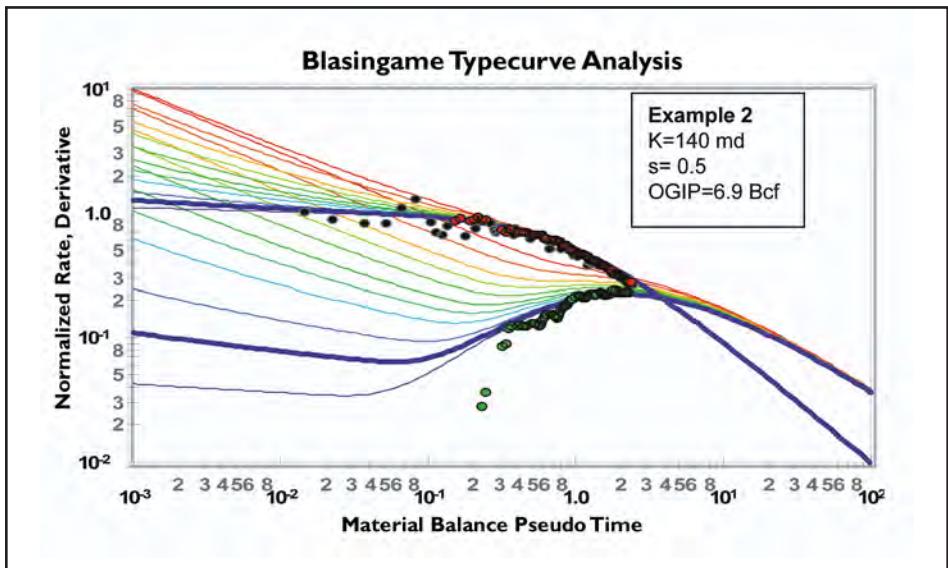


Figure 8.5. Rate transient analysis - type curve match - example 2.

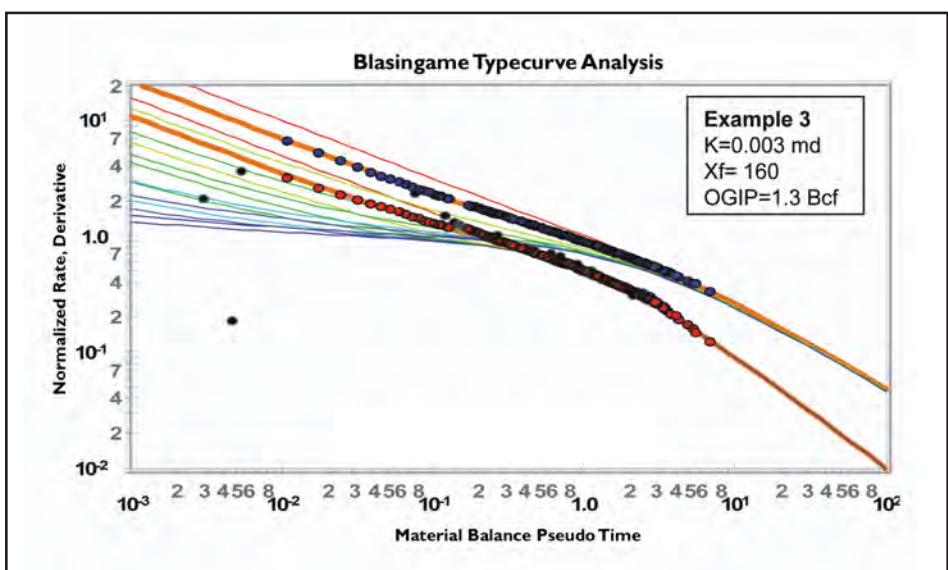


Figure 8.6. Rate transient analysis - type curve match - example 3.

well and has been analyzed using hyperbolic decline. The reserves are 5.0 Bcf which (using a recovery factor of 50% for tight gas) translates to an OGIP equal to 10 Bcf. By using the modern rate transient analysis described later in this article, it will be shown that this value of OGIP is overly optimistic.

Typically, the traditional methods of determining reserves do not work well when the operating conditions are variable, or in the case of tight gas. The above three examples fall into these categories, and while the results appear to be reasonable, it will be shown using the modern methods described below, that they are in error; sometimes by a significant amount.

#### MODERN METHODS: HYDROCARBONS-IN-PLACE AND RESERVOIR CHARACTERISTICS

There are two significant differences between the traditional methods and the modern methods:

- The traditional methods are empirical, whereas the modern methods are mechanistic, in that they are derived from reservoir engineering fundamentals.
- The traditional methods only analyze the flow rate, whereas the modern methods utilize both the flow rates and the flowing pressures.

The modern methods are known as rate transient analysis. They are an extension of well testing (Mattar, L. and Dean, L., 2008). They combine Darcy's law with the equation of state and material balance to obtain a differential equation, which is then solved analytically (Anderson, D. 2004; Mattar, L. 2004). The solution is usually presented as a "dimensionless type curve," one curve for each of the different boundary conditions, such as: vertical well, horizontal well, hydraulically fractured well, stimulated or damaged well, bounded reservoir, etc.

To analyze production data using rate transient analysis, the instantaneous flow rate ( $q$ ) and the corresponding flowing pressure ( $p_w$ ) are combined into a single variable called the normalized rate ( $= q/(\Delta p)$ ) and this is graphed against a time function called material-balance time. As in well testing (Mattar, L. and Dean, L., 2008), a derivative is also calculated. The resulting data set is plotted on a log-log plot of the same scale as the type curve, and the data moved vertically and horizontally until a match is obtained with one set of curves. Figure 8.4 shows the type curve match for the data of Example 1. This procedure is known as type

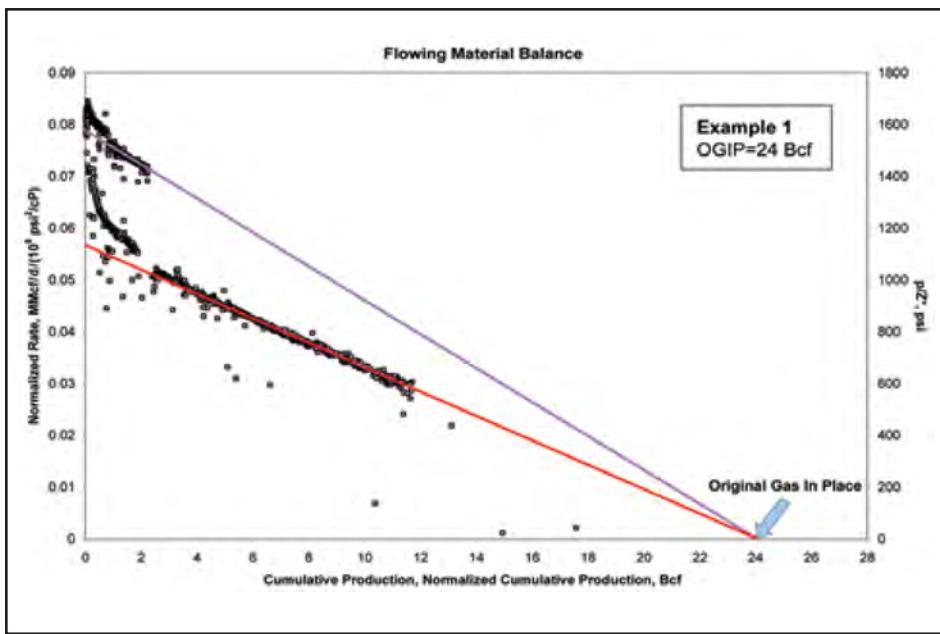


Figure 8.7. Flowing material balance - example 1.

curve matching, and the match point is used to calculate reservoir characteristics such as permeability, completion (fracture) effectiveness, and original-gas-in-place.

The data sets of Examples 2 and 3 have been analyzed in the same way, and the type curve matches are shown in Figures 8.5 and 8.6. Note that the type curves for each of these examples have different shapes because they represent different well/reservoir configurations. Figures 8.4 and 8.5 represent a damaged or acidized well in radial flow, whereas Figure 8.6 represents a hydraulically fractured well in linear flow.

In addition to the type curve matching procedure described above, another useful method of analysis is known as the flowing material balance (Mattar, L. and Anderson, D. M., 2005). The flow rates and the flowing pressures are manipulated in such a way that the flowing pressure at any time (while the well is producing) is converted mathematically into the average reservoir pressure that exists at that time. This calculated reservoir pressure is then analyzed by material balance methods (Mireault, R. and Dean, L., 2008), and the original-gas-in-place determined. The flowing material balance plot for the data set of Example 1 is shown in Figure 8.6, and the results are consistent with those of the type curve matching of Figure 8.4.

#### SUMMARY OF RESULTS:

When Examples 1, 2, and 3 are analyzed using modern Rate Transient Analysis, and the results compared to those from the traditional methods, the following volumes are obtained:

#### Example#: OGIP (Traditional) OGIP (Modern)

#1	3.6 Bcf	24 Bcf
#2	12.5 Bcf	6.9 Bcf
#3	10.0 Bcf	1.3 Bcf

The reasons for the discrepancies are different in each case. In Example 1, the flowing pressure was continuously increasing due to infill wells being added into the gathering systems, which caused an excessive production rate decline. In Example 2, the flow rate and flowing pressure were declining simultaneously. The decline in flow rate would have been more severe with a constant flowing pressure. In Example 3, the permeability is so small that the data is dominated by linear flow into the fracture (traditional methods are NOT valid in this flow regime).

In rate transient analysis, once the reservoir characteristics have been determined, a reservoir model is constructed to historymatch the measured data. The model is then used to forecast future production scenarios, such as different operating pressures, different completions, or well drilling density.

A word of caution is warranted. Data quality can range from good to bad. Multiphase flow, liquid loading in the wellbore, wellhead to bottomhole pressure conversions, interference from infill wells, multiwell pools, rate allocations, re-completions, and multilayer effects can all compromise data quality and complicate the analysis. Notwithstanding these potential complications, it has been our experience that significant knowledge has been gained by analyzing production data using the modern methods of rate transient analysis.

#### REFERENCES:

Anderson, D. 2004. Modern Production Decline Analysis, Getting the Most Out of Your Production Data. Technical Video 2. <http://www.fekete.com/aboutus/techlibrary.asp>.

Dean, L. and Mireault, R. 2008. Reservoir Engineering For Geologists, Part 4: Production Decline Analysis. Canadian Society of Petroleum Geologists Reservoir, Vol. 35, Issue 1. p. 20-22.

Mattar, L. 2004. Evaluating Gas-In-Place, Case Studies Using Flowing and Shut-In Data. Technical Video 4. <http://www.fekete.com/aboutus/techlibrary.asp>.

Mattar, L. and Anderson, D. M. 2005. Dynamic Material Balance (Oil or Gas-In-Place Without Shut-Ins). CIPC.

Mattar, L. and Dean, L. 2008. Reservoir Engineering For Geologists, Part 6: Well Test Interpretation. Canadian Society of Petroleum Geologists Reservoir, Vol. 35, Issue 3. p. 22-26.

Mireault, R. and Dean, L. 2008. Reservoir Engineering For Geologists, Part 5: Material Balance. Canadian Society of Petroleum Geologists Reservoir, Vol. 35, Issue 2. p. 24-26.



# RESERVOIR ENGINEERING FOR GEOLOGISTS

## Article 9 – Monte Carlo Simulation/Risk Assessment

by: Ray Mireault P. Eng. and Lisa Dean P. Geol., Fekete Associates Inc.

Geologist A is presenting a development prospect. Geologist B is presenting an exploration play. Which should you invest in?

This is a daily question in oil companies. A development prospect is generally considered a “safer” investment but the volume of hydrocarbons and its economic value is limited (Figure 9.1). The exploration prospect may carry more “dry hole” risk but a company has to make some exploration discoveries or it eventually runs out of development opportunities (Figure 9.2).

However, simply estimating the size of the deposit is not sufficient. Although Geologist A’s development prospect has a P10 to P90 recoverable gas range of between 258 and 1,219  $10^6 \text{ m}^3$  (10 to 43 BCF), it may or may not be a good investment. For example:

- Low permeability reservoir rock may restrict production rates so that each well recovers very little gas over time. The low rate/long life profile may actually have very little economic value.
- The combination of royalty rates, operating costs, processing fees, and transportation tariffs may mean that very little of the sales revenue is retained by the company, despite an apparently attractive commodity sale price outlook.
- Capital costs may simply be too great. If the prospect is located offshore (or at a remote onshore) location, the prospect may contain insufficient gas to offset the required investment capital.

Management needs to know the following about any exploration or development opportunity:

- What are the chances that at least the value of the capital investment will be recovered if we proceed?
- How much capital could be lost if events do not turn out as expected?
- What is the potential gain in economic value if events do unfold as expected?
- What is the total capital commitment required to realize production?

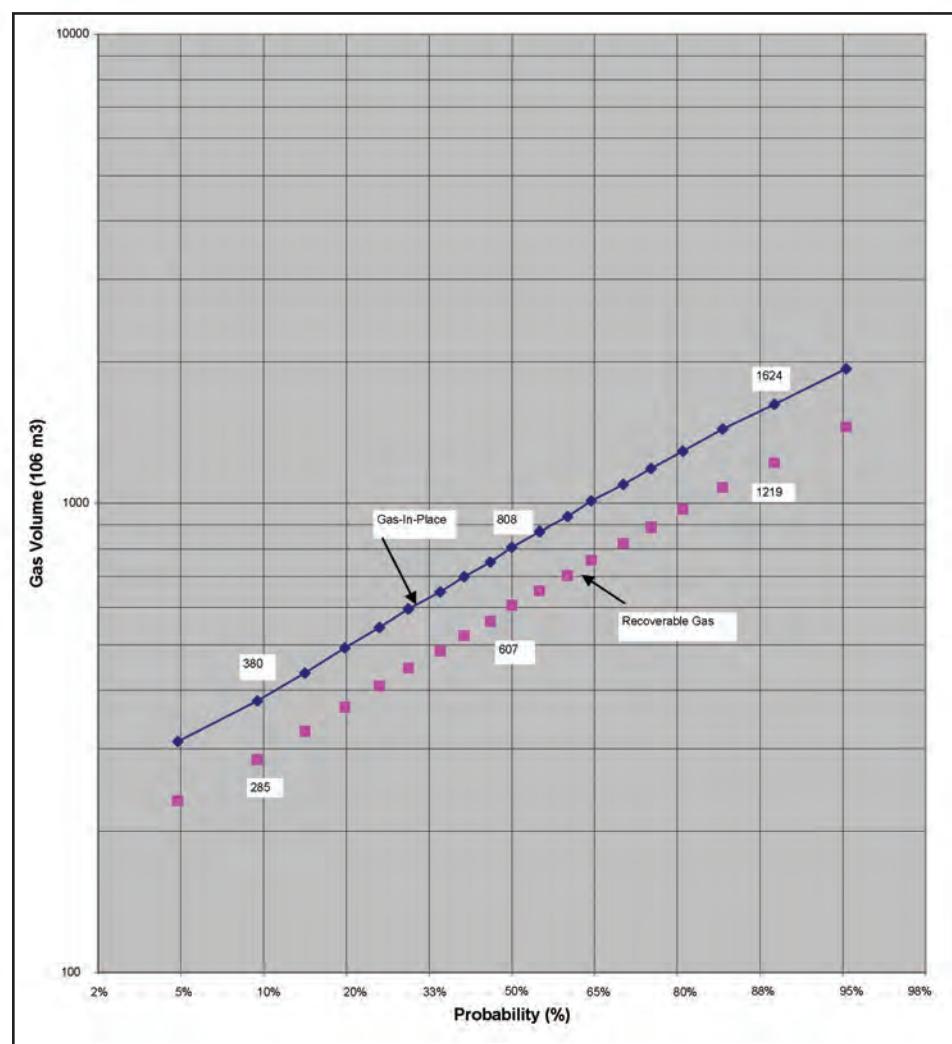


Figure 9.1. Probability chart, gas development prospect.

Answering the financial questions would be (relatively) easy if we knew exactly how much oil/gas is in place, the fraction that will be recovered, its sale price when produced, and the associated capital and operating costs. But prior to producing a deposit, we don’t know any of the foregoing with any degree of precision. We need to assess and balance the uncertainty in our technical knowledge against the impact that the uncertainty has on the expected financial performance (and capital exposure) of the investment.

When consistently applied, Monte Carlo simulation provides a tool to systematically assess the impact of technical uncertainty on financial performance. A consistent

approach also enables comparison and ranking of development and exploration opportunities, so a company can identify and pursue its better prospects.

In Fekete’s experience, the following assessment procedure provides a consistent approach to prospect evaluation:

1. Estimate the probable range in OOIP/OGIP from 3-point estimates for the input parameters in the volumetric equation.
2. Estimate the probable range in recovery factor from reservoir engineering principles, analogue performance, and/or reservoir simulation.

3. Estimate the total field/pool daily production rate range from the recoverable hydrocarbon range based on a seven year rate-of-take (deplete the field in about 15 years).
4. Estimate the number of wells required to achieve the projected daily production rate from reservoir rock characteristics and test well performance.
5. Estimate the type and size of pipelines, wellsite, and plant facilities required to produce at the forecasted production rates.
6. Estimate operating costs and assess the present day value of production from economic runs. This is the discounted present day value of the sales price less royalties, operating costs, processing fees, and transportation tariffs.
7. Estimate well and facility capital costs.
8. Compare the probable range in economic value to the required capital investment range. Quantify the chances of recovering the capital investment, the expected return on investment, the capital exposure, and the total capital commitment.

The job of the earth sciences (geology, geophysics, reservoir engineering) in a Monte Carlo evaluation is to develop input parameter ranges that reflect the current state of knowledge for the prospect. The recommended approach is an integrated approach that first develops minimum and maximum values that are consistent with the known facts. The end point values must encompass the true value with a high (90 to 95%) degree of certainty. The most likely value is estimated only after establishing the possible range in the parameter values.

Geologist A's development prospect is a structural trap with 4-way closure that contains a series of stacked fluvial sands at a depth of about 400 m. The sands were initially deposited in a broad valley and are capped with a thick shale sequence. Subsequent basement uplift created the present drape structure. Drilling results to date set the minimum area of the deposit at 600 ha. Based on the seismic interpretation, the areal extent is most likely about 1000 ha but it could be as large as 1,600 ha (the maximum closure area with the existing data).

The structure is estimated to contain about 46 m of gross sand thickness within a 60 m gross interval. Due to fluvial deposition, the areal extent of an individual sand body is

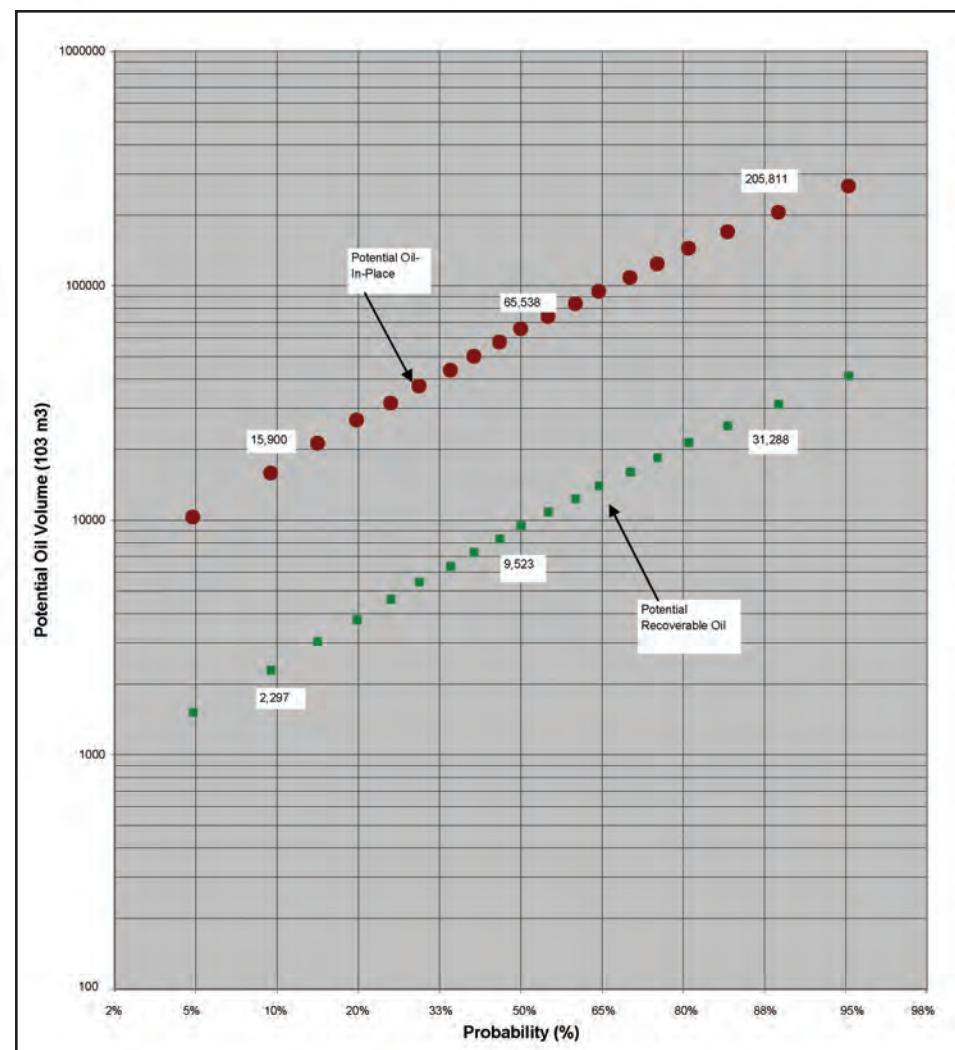


Figure 9.2 Probability chart, oil exploration prospect.

expected to be limited and so not all sands are expected to be gas charged. Accordingly, the average net pay is estimated to be between 12 and 46 m but will most likely be about 21 m.

The geological model and limited cuttings analysis suggest that sand porosity also varies. If the deposit is dominated by argillaceous, highly cemented sands, then average porosity could be as low as 8%. However, porosity will be either better developed or better preserved when fluvial rock is saturated with hydrocarbons, so a large percentage of ultra-clean sands could push the average porosity value to as much as 18%. Assuming average quality sands, porosity will most likely be about 12%.

Currently, there is no good basis from which to estimate the residual water saturation in the gas-bearing sands. The best value for good-quality sands would be 15% Sw. An average water saturation value for the "dirty" fine-grained sands might be about 40% but could be as high as 60% (the maximum value

for fine-grained sand).

Well test data indicates that the deposit contains a sweet, 0.7 gravity gas. Two pressure buildup tests indicate a reservoir pressure of 3,448 and 4,138 kPa(abs) for an arithmetic average of 3,793 kPa(abs). Reservoir temperature is estimated at 38°C. The gas deviation factor (Z) at initial reservoir conditions is estimated to be about 0.9.

Sand permeability is expected to vary considerably between individual sands with a range of 3 to 30 mD. Based on experience and reservoir engineering principles, gas recovery from volumetric expansion of a reservoir at shallow depth is generally in the order of 70 to 85%. Due to the limited areal extent of the sands, the most likely value is estimated at 75%.

The following table summarizes the input parameters that were used to develop the volumetric estimates of gas-in-place and recoverable gas for the development prospect:

$$OGIP = A \cdot h \cdot \phi \cdot (1 - Sw) \cdot ((T_s \cdot P_i) / (P_s \cdot T_f \cdot Z))$$

Parameter	Min	Most Likely	Max
Area (ha)	600	1000	1600
Net Pay m	12	21	46
Porosity	8%	12%	18%
Water Saturation%	15%	40%	60%
Reservoir Pressure kPa(a)	3448	3793	4138
Recovery Factor	70%	75%	85%
Reservoir Temperature °C		38	
Gas Deviation Factor Z		0.9	

Once 3-point estimates have been developed, Monte Carlo simulation can be used to calculate the gas-in-place and recoverable gas volumes. Monte Carlo simulation consists of randomly selecting values for each input parameter and calculating a gas-in-place and recoverable gas volume. Many iterations (in this case 10,000) creates gas-in-place and recoverable gas distributions.

From the simulation, Geologist A's gas development prospect has an 80% probability of containing between 380 and 1,624  $10^6\text{m}^3$  of gas-in-place. Based on the technical input, there is an 80% chance that the recoverable gas volume is between 285 and 1,219  $10^6\text{m}^3$  of gas. The mathematical significance of the P50 value is that it is the number that splits the distribution into 2 equal halves.

An obvious question is why can't we simply multiply all the minimum input parameter values to determine the minimum gas volume and all the maximum values for the maximum volume? Doing so yields the following values:

	Min	Most Likely	Max
Gas-in-Place $10^6\text{m}^3$	171	582	4,565
Recoverable Gas $10^6\text{m}^3$	120	437	3,880

	P90 $10^6\text{m}^3$	P90 $10^6\text{m}^3$	P90 $10^6\text{m}^3$
Gas-in-Place	380	808	1624
Recoverable Gas	285	607	1219

As can be seen, the minimum values are much less than the P90 values calculated previously and the maximum values are much greater. Even a calculation using the most likely values doesn't match the P50 values very well. From inspection of the probability graph (Figure 9.1) the chances of recovering more than 120  $10^6\text{m}^3$  of gas are greater than 98% (100%). At the other end of the scale, there is less than a 2% chance of producing 3,880  $10^6\text{m}^3$  from the prospect (the probability value corresponding to 3,880  $10^6\text{m}^3$  is well off the scale).

The reason for the large discrepancies is because the error in the product of multiplication successively increases with each multiplication, unlike addition. To illustrate, if the estimated value for each input parameter is out by 17%, the sum of addition will also be out by 17%. Not so with multiplication:

	-17% Error	Correct	+17% Error	Alternating
A	5	6	7	7
h	5	6	7	5
$\Phi$	5	6	7	7
I-Sw	5	6	7	5
Addition	20	24	28	24
Error	83%		117%	100%
Multiplication	625	1296	2401	1225
Error	48%		185%	95%

Even alternating from a conservative to an optimistic estimate doesn't completely cancel out the errors when multiplying.



# Reservoir Engineering for Geologists

## *Article 10 – Monte Carlo Simulation/Risk Assessment (cont.)*

by: Ray Mireault, P. Eng. and Lisa Dean, P. Geol., Fekete Associates Inc.

In the introductory article (Article 9), recoverable gas from Geologist A's development prospect was estimated to be between 285 and 1,219  $10^6\text{m}^3$  of gas.

	P90 $10^6\text{m}^3$	P50 $10^6\text{m}^3$	P10 $10^6\text{m}^3$
Gas-in-Place	380	808	1624
Recoverable Gas	285	607	1219

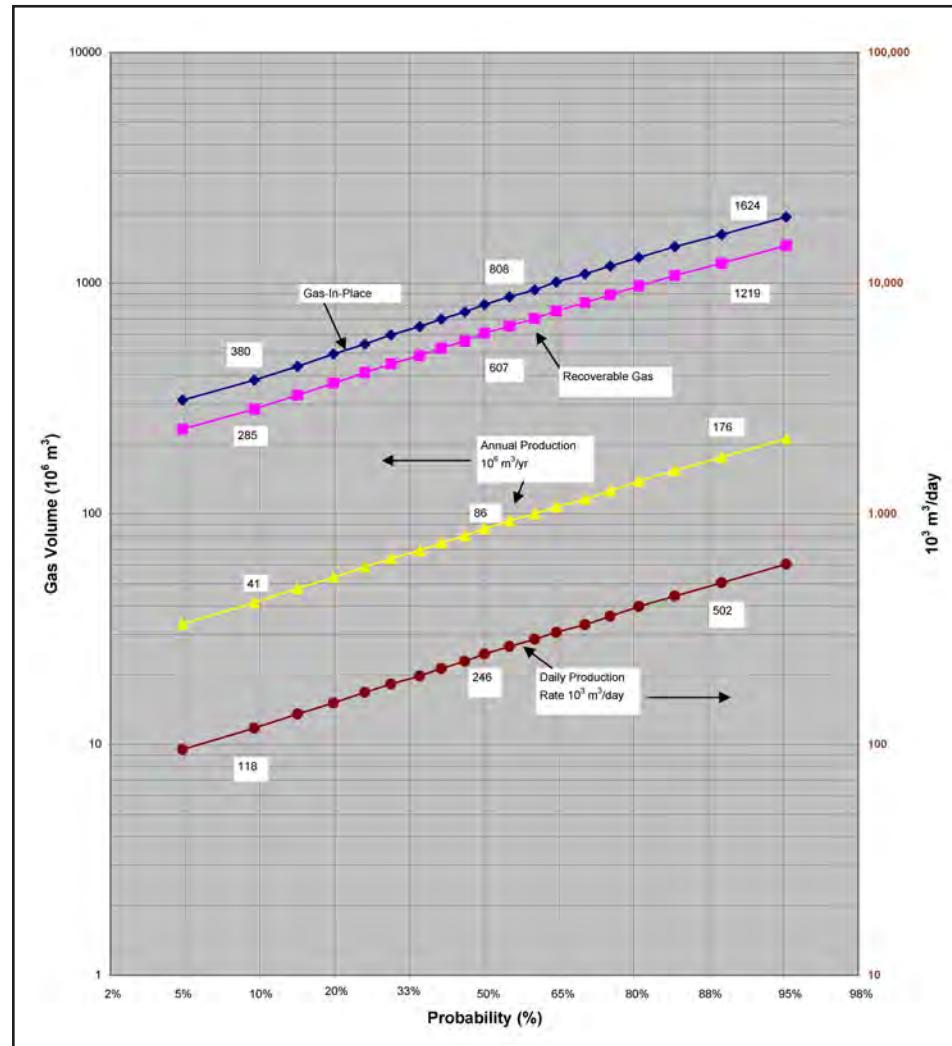
What is this gas worth? The first factor to consider is the time value of production. The following chart presents the present day value of \$100 of future year's production at a 12% discount rate.

<b>Year 1</b>	<b>\$88.00</b>	<b>Year 8</b>	<b>\$35.96</b>	<b>Year 15</b>	<b>\$14.70</b>
<b>Year 2</b>	<b>\$77.44</b>	<b>Year 9</b>	<b>\$31.65</b>	<b>Year 16</b>	<b>\$12.93</b>
<b>Year 3</b>	<b>\$68.15</b>	<b>Year 10</b>	<b>\$27.85</b>	<b>Year 17</b>	<b>\$11.38</b>
<b>Year 4</b>	<b>\$59.97</b>	<b>Year 11</b>	<b>\$24.51</b>	<b>Year 18</b>	<b>\$10.02</b>
<b>Year 5</b>	<b>\$52.77</b>	<b>Year 12</b>	<b>\$21.57</b>	<b>Year 19</b>	<b>\$ 8.81</b>
<b>Year 6</b>	<b>\$46.44</b>	<b>Year 13</b>	<b>\$18.98</b>	<b>Year 20</b>	<b>\$ 7.76</b>
<b>Year 7</b>	<b>\$40.87</b>	<b>Year 14</b>	<b>\$16.70</b>		

While \$100 received today is worth \$100, next year's production is only worth 88% of today's value. In year five it is only worth 52.77%; in year ten, 27.85% and in year 20, 7.76%. Clearly, we would like to produce the gas as quickly as possible to maximize its value but there is a limit. Each incremental increase in production rate requires more wells and larger, more costly facilities so that eventually the incremental value of further acceleration cannot offset the increased capital requirement.

What should we assume for a depletion rate? In Fekete's experience, a seven-year rate-of-take provides a starting point for a production profile with good economic value. Note that the calculation provides an estimate of the annual produced volume during the initial one-to-three years of production. Since well productivity declines over time, it will take between 10 and 15 years to produce the prospect to depletion but about half the gas will be recovered during the initial five years.

Dividing Geologist A's recoverable gas range by seven yields an initial annual production volume of between 41 and 176  $10^6 \text{m}^3/\text{yr}$  (Figure 10.1). A daily production rate of



*Figure 10.1. Probability chart, gas development prospect.*

between 118 and 502  $10^3 \text{m}^3/\text{day}$  (also Figure 10.1) was obtained by dividing the annual volume range by 350 producing days per year.

With an estimated daily rate and knowledge of the gas composition, the type and size of the central facilities can be determined. Since the gas contains mostly methane and ethane with no  $\text{H}_2\text{S}$  and a low concentration of other nonhydrocarbon gases, only dehydration and compression will be required to treat the raw gas to sales gas specifications. If the design capacity of the facilities is set at  $236 \text{ } 10^3 \text{m}^3/\text{day}$  of raw gas, a plant with a (typical) 2:1 turndown ratio will be able to operate down to about  $118 \text{ } 10^3 \text{m}^3/\text{day}$ .

By inspection of Figure 1, 118 103m<sup>3</sup>/day corresponds to the 10th percentile of the daily production rate curve and 236 103m<sup>3</sup>/day is about the 47th percentile. The plant is the correct size for the lower 37% of the range and thus capital and operating costs for the central facilities can be estimated. If development drilling ultimately proves that larger facilities are required, increased gas revenues will more than offset the incremental cost of larger facilities.

Geologist A's prospect also requires a 70 km sales gas pipeline to connect to the nearest sales point. The central facility design rate can similarly be used to estimate the size and associated capital and operating

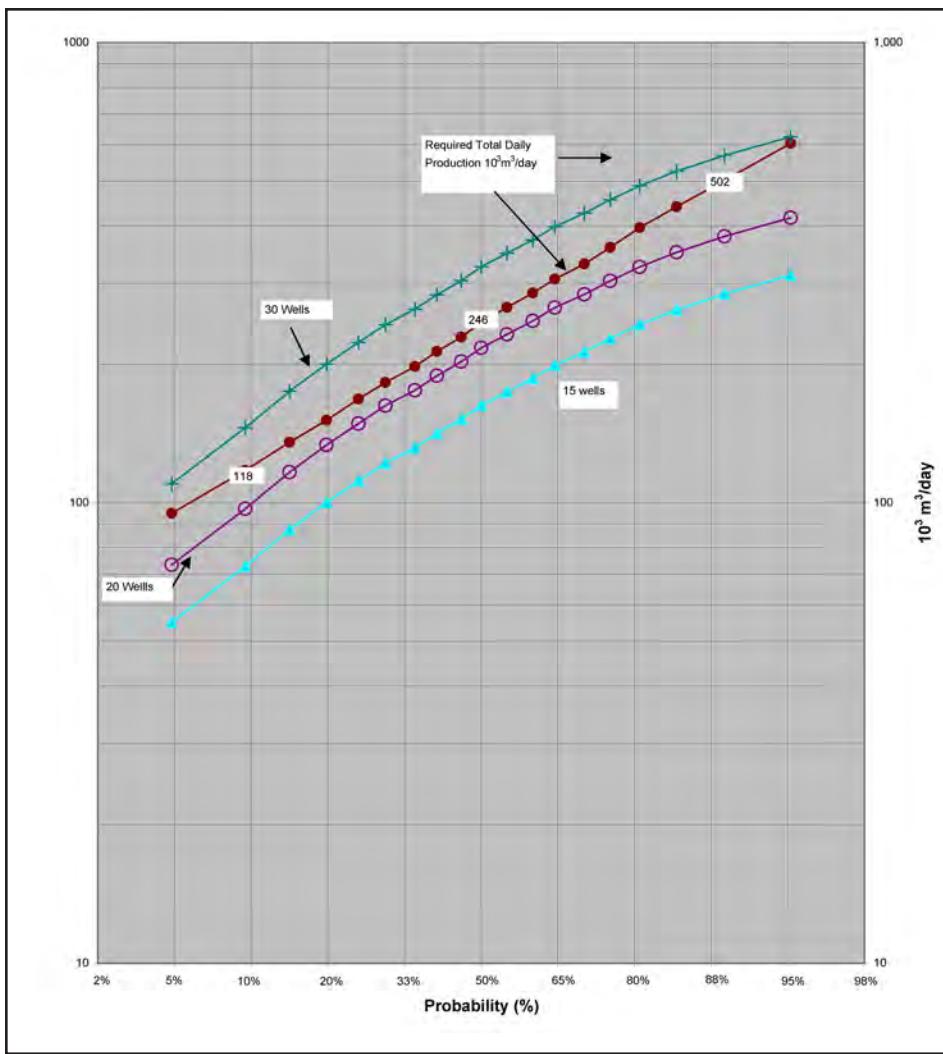


Figure 10.2. Probability chart, gas development prospect number of wells required.

costs of the sales gas pipeline. Accounting for processing shrinkage and fuel gas consumption, the  $236 \text{ } 10^3 \text{m}^3/\text{day}$  raw gas production rate equates to  $217 \text{ } 10^3 \text{m}^3/\text{day}$  of sales gas.

The next issue is the number of wells required to produce at the desired rate. From the available test information, a well's 1st year average production rate, based on the year's production volume, could range from 3 to  $21 \text{ } 10^3 \text{m}^3/\text{day}$  but most likely will be about  $8.5 \text{ } 10^3 \text{m}^3/\text{day}$ . Multiplying the range for an individual well by the number of wells yields deliverability curves for the selected numbers of wells. From inspection of Figure 2, about 22 wells will most likely be required to provide the required deliverability for the prospect but as few as 15 or as many as 30 wells may be needed.

Knowing the number of wells, a scoping level layout of the well locations and the production gathering system can be undertaken. The scoping plan addresses issues such as the timing and sequencing of well drilling, drilling and completion design,

surface access, the required wellsite facilities, and wellsite layouts. The level of effort expended is just sufficient to develop three-point estimates for the capital and operating costs of system components.

Contractual terms are obtained from the licence/lease agreement while a price forecast(s) for the production period may be obtained from a variety of sources. At this point, estimate ranges have been

developed for all the inputs necessary to evaluate the economics of the prospect. The general calculation sequence is:

- Calculate the net cash flow for each year's production,  $\text{NCF} = (\text{Sales Volume} * \text{Sales Price}) - \text{Royalties} - \text{Operating Costs} - \text{Taxes} - \text{Capital}$
- Discount each year's net cash flow to its present day value
- Sum each year's discounted value to arrive at the prospect net present value  $\text{NPV} = \sum \{\text{Yearly NCF} * \text{Yearly Discount Factor}\}$  (See table 10.1.)

The calculations are amenable to spreadsheet analysis (Table 10.1) and Monte Carlo simulation. Since no two prospects are exactly alike, the calculations and their presentation can and should be modified to fit the details of each particular situation.

Although the final goal of Monte Carlo is to generate the expected NPV range for Geologist A's prospect, Fekete has found it useful to calculate some intermediate values as follows:

- Calculate the cash flow for each year's production before capital investment,  $\text{CF} = (\text{Sales Volume} * \text{Sales Price}) - \text{Royalties} - \text{Operating Costs} - \text{Taxes}$
- Discount each year's cash flow to its present day value ( $\text{PV}$ )
- Sum each year's discounted value to arrive at the prospect present day value  $\text{PVCF} = \sum \{\text{Yearly CF} * \text{Yearly Discount Factor}\}$
- Categorize each year's capital investment and discount it to its present day value  
 $\text{PV}_{\text{capital}} = \text{Sales line} * \text{DF} + \text{Plant} * \text{DF} + \text{Gathering System} * \text{DF} + \text{Dev. Wells} * \text{DF}$   
 $\text{PV}_{\text{capital}} = \sum \{\text{PV}_{\text{sales lines}} + \text{PV}_{\text{plant}} + \text{PV}_{\text{gathering system}} + \text{PV}_{\text{dev. wells}}\}$
- Calculate the net present value  $\text{NPV} = \text{PVCF} - \text{PV}_{\text{capital}}$

The mathematical manipulation generates the same NPV range for a prospect. But

Year	Annual Sales Volume $10^3 \text{m}^3$	Sales Price $$/10^3 \text{m}^3$	Less Royalty $\$$	Less Total Opex $\$$	Less Taxes $\$$	Cash Flow Before Capital $\$$	PV Before Investment @ 12% $\$$	Capital Invested $\$$	PV of Capital @ 12% $\$$	Annual Net Cash Flow $\$$	Net Present Value @ 12% $\$$
1											
2											
3											
4											
5											
TOTAL											

Table 10.1. Example input spreadsheet, in any given year. Net present value @ 12% = annual net cash flow \* 12% discount factor. Net present value @ 12% = PV before investment @ 12% - PV of capital investment.

additionally, the present day value of a unit of production can be estimated by dividing the prospect's present day value before capital (highlighted in blue) by the projected total gas sales volume (in pink).

In Fekete's experience, the uncertainty range on the present day value of a unit of production is relatively small compared to the uncertainty range of the input parameters. The reason is because increased sales revenue, due to higher production volumes and/or gas prices tends to be offset by increased royalties, operating costs, and taxes. Conversely, lower revenue scenarios have reduced royalties, operating costs, and taxes.

At the time that Geologist A's prospect was evaluated, its unit of production PV was estimated to be between \$35.50 and \$71 per  $10^3\text{m}^3$  (\$1 to \$2/Mcf). Using Monte Carlo simulation to multiply the unit PV by the recoverable gas estimate yields the present day value of the prospect before capital investment. As shown in Figure 10.3, there is an 80% probability (P10 to P90 values)

that Geologist A's prospect has a present day value before capital of between \$12 and \$66 Million.

While the PV before investment range looks promising, it must be compared with the required capital investment to know if the prospect has economic potential. The present value capital costs for the prospect were estimated for each category as follows:

Capital Cost Estimates			
	All values in Millions of Dollars		
Item	Low	Medium	High
Sales pipeline	9	13	16
Plant	4	4.8	5.9
Gathering System	2.4	3.2	3.9
Well Cost \$MM/well	0.25	0.3	0.4
Wellsite costs \$MM/well	0.1	0.15	0.2
Drilling Success Rate	70%	80%	85%
Dry Hole Cost \$MM/hole	0.15	0.2	0.3

Monte Carlo simulation can be used to successively add the cost range for each

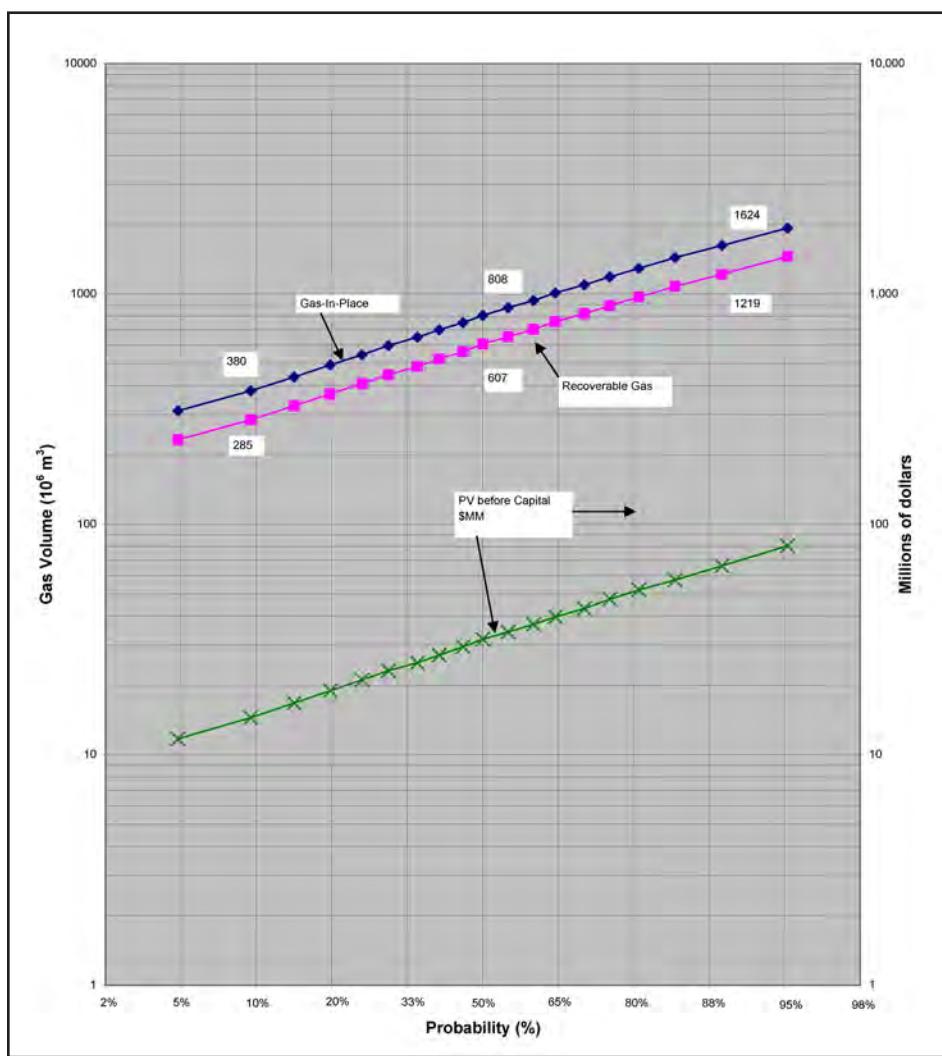


Figure 10.3. Probability chart, gas development prospect present value (PV).

category and estimate the total capital cost range for the project. Cost estimates for well costs and wellsites facilities that were provided on a per well basis were added together and then multiplied by the distribution for the expected number of development wells to determine the total cost range for the development well category.

The development well category should also include the cost of the dry holes that will be encountered. The number of dry holes can be estimated by dividing the number of wells required by the drilling success rate to yield the total number of drilling attempts that must be undertaken. Multiplying by the chance of a dry hole (between 15 and 30%) yields the number of dry holes that are likely to be encountered. Multiplying by the cost per dry hole yields an estimated range of values for total dry hole cost. The updated capital cost table follows:

Capital Cost Estimates			
	All values in Millions of Dollars		
Item	Low	Medium	High
Sales pipeline	9	13	16
Plant	4	4.8	5.9
Gathering System	2.4	3.2	3.9
Wells & Wellsites Cost	6.8	10.4	14.8
Dry Hole Costs	0.7	1.3	2.3

As can be observed, the sales pipeline and the wells are the two largest capital cost categories. Monte Carlo simulation is once more used to add the separate cost distributions and estimate the range of total costs for the project. In Fekete's experience it is useful to track the effect of each successive cost category on the total cost profile as follows:

Cumulative Costs				
	All values in Millions of Dollars			
Item	Total Project Costs	P10	P50	P90
Sales pipeline	10.0	12.8	15.4	
Sales P/L + Plant	14.8	17.7	20.4	
Sales P/L + Plant + Gathering System	18.0	20.9	23.6	
Sales P/L + Plant + Gathering System + Wells + Dry Hole costs	28.3	32.7	37.3	

From Figure 10.4 (p. 40), the P10 (blue line) and P90 (upper red line) values of the capital cost range intersect the PV before capital investment curve at about the 43rd and 63rd percentiles. Thus the prospect has between a 37 and 57% chance of achieving a positive NPV. The graph also illustrates that even at the upper end of the reserve range we



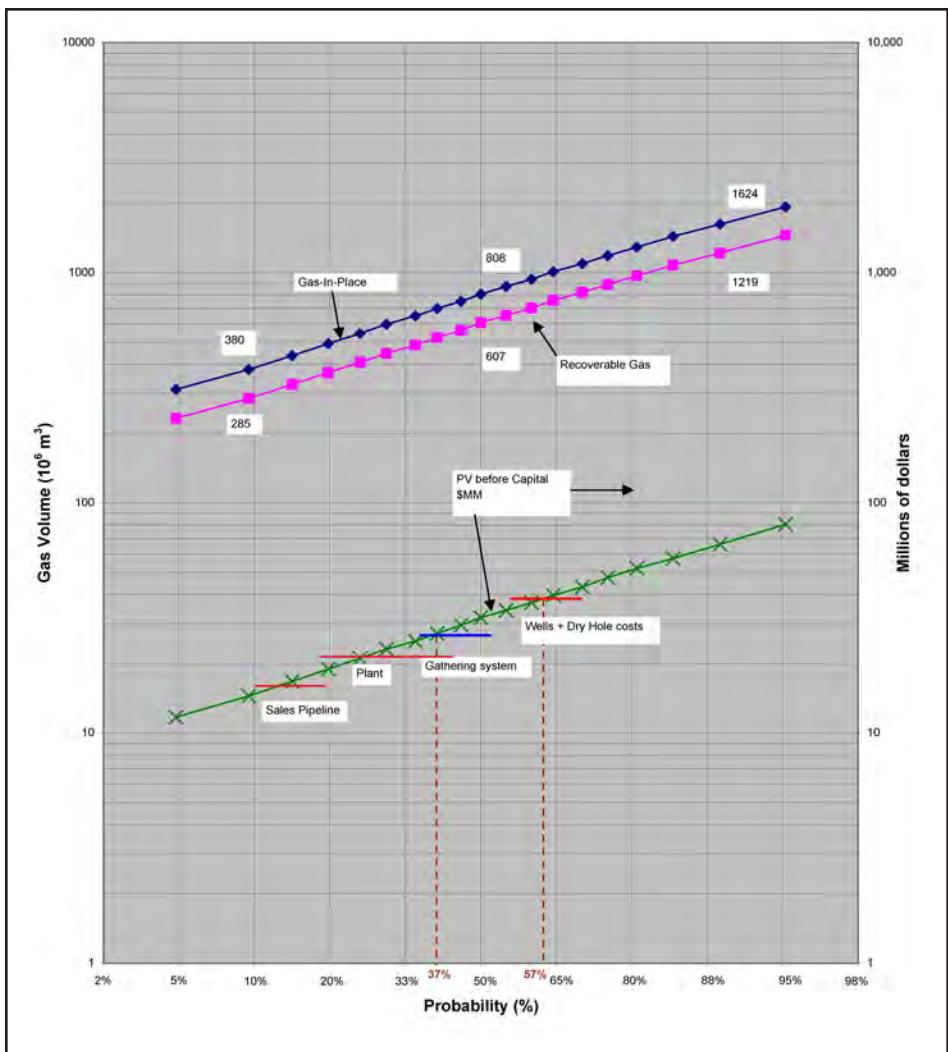


Figure 10.4. Probability chart, gas development prospect PV vs. Capital.

cannot do any better than double the value of the capital invested and that the sales pipeline and well costs have the greatest impact on financial performance.

Should a prospect with these financial characteristics be developed? One company may choose to develop the prospect because this is the best investment opportunity available at the time. Another may determine that its time has not yet come and choose to wait until the price of gas rises sufficiently and/or other developments in the area reduce the distance and cost of the sales pipeline. Either way, a consistent Monte Carlo evaluation methodology helps management make informed decisions.

Can Monte Carlo simulation also evaluate Geologist B's exploration prospect? We'll show you how in the next issue of the Reservoir.

#### REFERENCES

Mackay, Virginia (ed.). 1994. Determination of Oil and Gas Reserves. Petroleum Society Monograph No. 1, p. 106-119.

Otis, Robert M. and Schneidermann, Nahum 1997. A Process for Evaluating Exploration Prospects, AAPG Bulletin, v. 81 p. 1087- 1109.

Pallisade @ Risk Guide. Version 4.5 November, 2005



# RESERVOIR ENGINEERING FOR GEOLOGISTS

## Article 11 – Monte Carlo Simulation/Risk Assessment (cont.)

by Ray Mireault, P. Eng. and Lisa Dean, P. Geol., Fekete Associates Inc.

The second article (Mireault and Dean, 2008) in the series on Monte Carlo simulation presented an evaluation methodology for Geologist A's development prospect. This last article extends the methodology to address Geologist B's exploration prospect.

Geologist B interprets a hydrocarbon-bearing reef at approximately 1,500 m depth from the available seismic data. Wrench tectonics and strike-slip faults influence the structural aspects of the play. Underlying shale represents a potential local hydrocarbon source while overlying lime mudstones and calcareous shales form the prospective cap rock.

Core samples and outcrops show up to 30% porosity and are considered to reflect an in situ combination of intra-crystalline and vuggy (moldic) porosity. In situ primary porosity may / may not have been altered over time.

Organic geochemistry suggests a Type II marine algal source charged the reservoir target with light (35-40° API) sweet oil. Reservoir reef and trap geometry are interpreted to have been in place at the time of oil generation.

Carbonate reef deposits tend to be oil-wet systems and this particular prospect is interpreted to sit on basinal material that precludes the existence of a mobile aquifer underlying the reef. Accordingly, water saturation should approach residual values. Solution gas drive is anticipated with primary recovery in the range of 10 to 20%.

From the viewpoint of a Monte Carlo simulation, after an exploration prospect has been discovered it will require development capital to achieve production, just like any other development prospect. Thus an exploration prospect is no more than a development prospect with an additional step. Accordingly, the financial questions to be answered become:

- Does the prospect present sufficient economic potential to proceed with development (assuming it contains the postulated volume of hydrocarbons)? If so,
- How much additional ("risk") capital is required to create a high (70%) probability of locating a hydrocarbon-

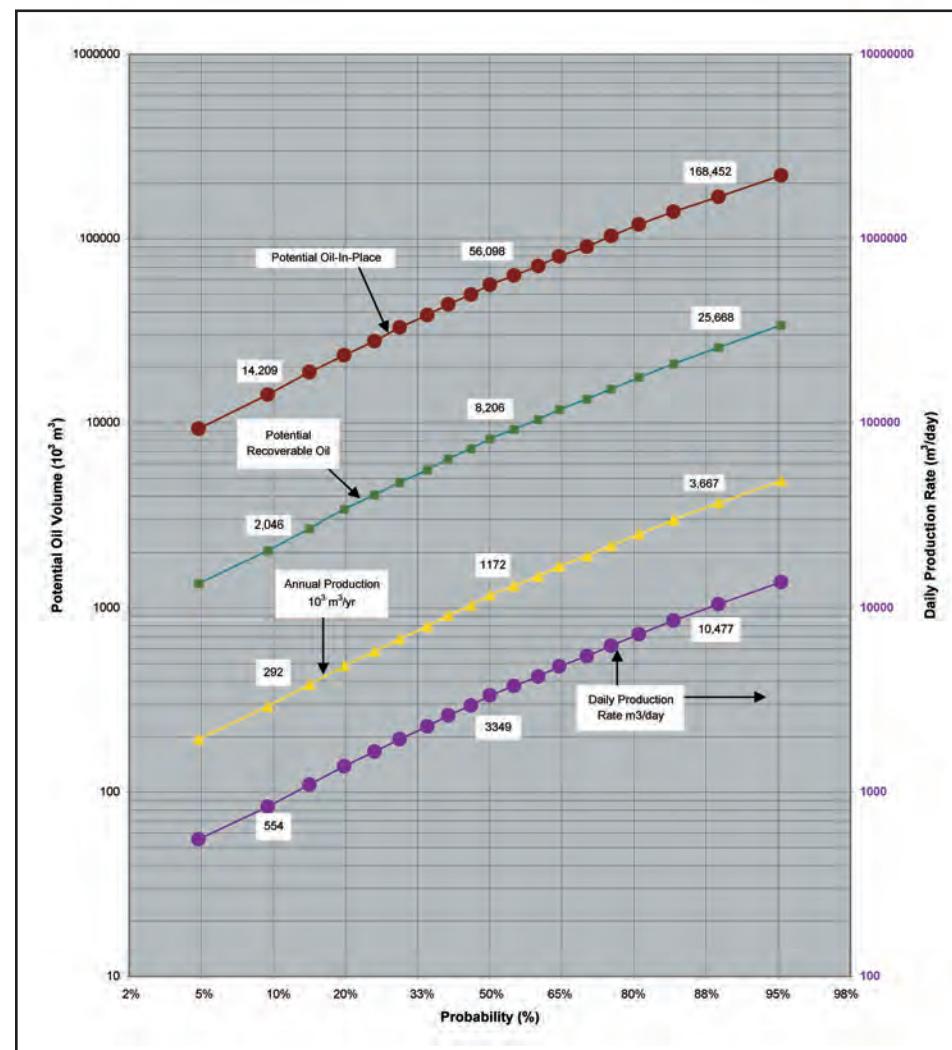


Figure 11.1. Oil exploration prospect.

bearing deposit (i.e., how many exploratory wells need to be drilled)?

- Are the prospect economics sufficiently attractive to accommodate both the development and exploration costs?

### DEVELOPMENT EVALUATION COMPONENT

As with Geologist A's development prospect, Monte Carlo simulation was used to volumetrically estimate the potential oil-in-place and recoverable oil volumes. Geologist B's input parameter ranges are in Table I.

As presented in the Volumetric Estimation article (Dean, 2008), the equations for oil are:

Parameter	Minimum	Most Likely	Maximum
Area (ha)	200	800	2000
Net Pay m	6	30	120
Porosity	6%	15%	30%
Water Saturation	8%	15%	20%
Shrinkage I/B <sub>o</sub>	81%	83%	85%
Recovery Factor	10%	15%	20%

Table 11.1. Geologist B's input parameter ranges.

$$OOIP = A * h * \phi * (1 - Sw) * I/B_o$$

$$\text{Recoverable Oil} = OOIP * \text{Recovery Factor}$$

Figure 11.1 graphically presents the prospect potential based on the foregoing input parameters. Dividing the recoverable oil

range by a seven-year rate-of-take provides the initial annual production volume. The initial daily production rate assumes 350 producing days per year.

Theoretical estimates of well production capability range between 80 and 320 m<sup>3</sup>/day. From the graphical comparison of Figure 11.2, between 6 and 20 wells will probably be required to achieve the initial target production rate, with 12 wells as a most likely value.

	P10	P50	P90
Oil-in-Place 10 <sup>3</sup> m <sup>3</sup>	14,209	56,098	168,452
Recoverable Oil 10 <sup>3</sup> m <sup>3</sup>	2,046	8,206	25,668
Annual Volume 10 <sup>3</sup> m <sup>3</sup> /yr	292	1,172	3,667
Initial Daily Rate m <sup>3</sup> /day	554	3,349	10,477

Table 11.2. Estimated volumes.

At the time Geologist B's prospect was evaluated, the present-day (PV) value of a cubic metre of production was estimated to be between \$25 and \$38/m<sup>3</sup>. Based on the estimate, the expected PV before capital for the prospect is between \$62 MM and \$798 MM (Figure 11.3).

The development capital items and their associated capital costs at the time of the evaluation are summarized in Table 11.3.

Item	Low	Medium	High
Sales pipeline	3.0	4.5	7.0
Plant and Infrastructure	10	13	18
Gathering System	2.0	2.5	3.0
Well Cost \$MM/well	0.8	0.9	1.0
Wellsite costs \$MM/well	0.05	0.06	0.07
Development Well Success Rate	70%	80%	85%
Dry Hole Cost \$MM/hole	0.7	0.8	1.0

Table 11.3. Capital Cost Estimates (all values in millions of dollars).

Based on the estimate of between 6 and 20 development wells and the cost estimates for an individual well (and dry hole) Monte Carlo simulation was used to generate the required range of development drilling capital (Table 11.4).

Total Development Costs			
Item	P10	P50	P90
Successful Well Costs	7.6	12.7	18.6
Dry Hole Costs	1.6	2.9	4.7
Total Development Drilling	9.4	15.7	23.1

Table 11.4. Development Drilling Costs (all values in millions of dollars).

Simulation was also used to generate the cumulative development cost profile for the

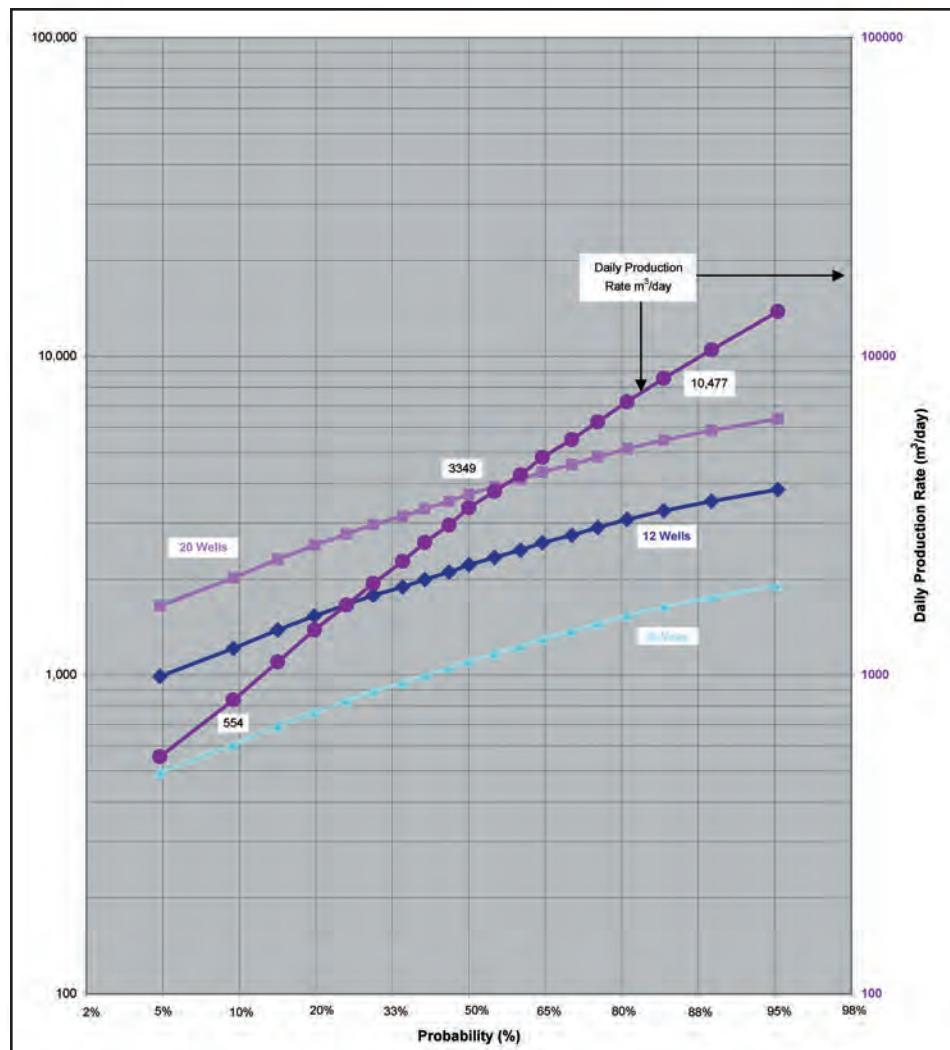


Figure 11.2. Oil exploration prospect number of wells required.

prospect from the individual capital cost ranges (Table 11.5).

Total Development Costs			
Item	P10	P50	P90
Sales Pipeline	3.0	4.6	6.4
Sales P/L + Plant	15.5	18.8	22.2
Sales P/L + Plant + Gathering System	17.8	21.1	24.6
Sales P/L + Plant + Gathering System + Dev. Drilling	29.9	37.0	44.9

Table 11.5. Cumulative Development Costs (all values in millions of dollars).

By inspection of Figure 11.3, the P90 limit of total development costs (\$44.9 MM) intersects the PV before Capital Curve at about the 6th percentile. Thus, there is in excess of a 94% chance that the prospect, as postulated to exist, would achieve a positive NPV on the development capital. With this chance of success, most companies would give the prospect further consideration.

## EXPLORATION “RISK” CAPITAL ESTIMATES

Unlike development capital, which always generates some cash flow from subsequent production, exploration “risk” capital is spent without any potential for immediate revenue generation. The majority of an exploration prospect’s risk capital consists of:

- The up-front (land) cost for the right to explore for hydrocarbons on specified acreage.
- Data acquisition (largely seismic) costs to infer the presence of prospect(s).
- Exploration drilling to locate a hydrocarbonbearing deposit.
- For offshore exploration, follow-up delineation drilling to confirm the minimum size of deposit needed for development.

Estimating “land” and seismic acquisition



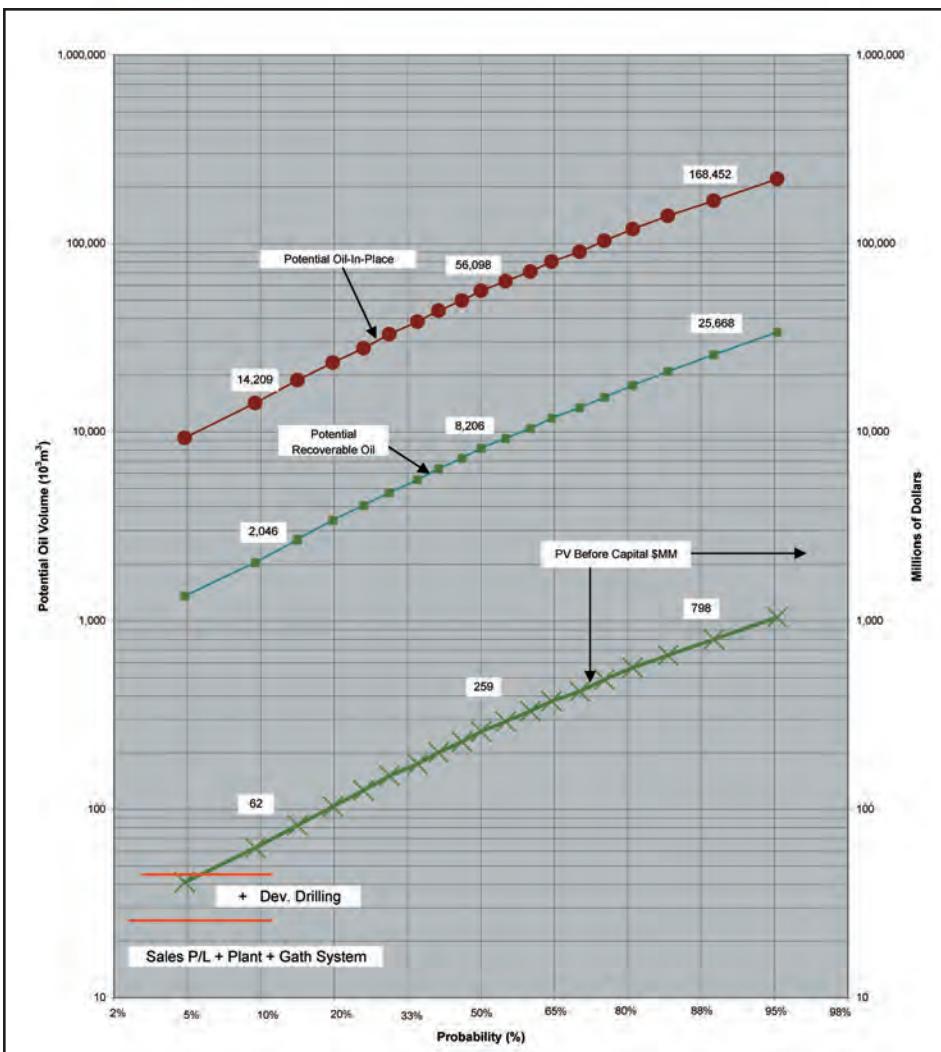


Figure 11.3. Oil exploration prospect present value (PV) potential.

costs is generally straight forward. However, the exploration drilling cost estimate is essentially the number of consecutive dry holes that will be drilled prior to making a discovery times the cost per dry hole. Exploration drilling is evaluated as a component of the total "risk" capital because 80 to 97% of the time, the outcome of an individual drilling attempt is a dry hole. Further, offshore exploration (and delineation) wells are abandoned after testing, irrespective of what they encounter. For onshore evaluations, the successful discovery well can be treated as the first development well, as was done for Geologist B's prospect, or as a "salvaged" exploration attempt.

Otis and Schneidermann (1997) present the concept of geological success for an exploration well as "having a sustained stabilized flow of hydrocarbons on test." They estimate the probability of geologic success ( $P_g$ ) as the product of the individual probabilities of occurrence for four factors as follows:

$$P_g = P_{\text{source}} * P_{\text{reservoir}} * P_{\text{trap}} * P_{\text{dynamics}}$$

where:

- $P_{\text{source}}$  is the probability of mature source rock
- $P_{\text{reservoir}}$  is the probability that reservoir quality rock exists
- $P_{\text{trap}}$  is the probability that a trap exists
- $P_{\text{dynamics}}$  is the probability of appropriate timing for migration and trapping

A neutral assessment is assigned a value of 0.5. Indirect supportive data increases the assigned probability of occurrence while non-supportive data reduces the estimated value. The approach has the advantage that a neutral (50% probability) assignment for all 4 factors yields a 6.25% probability of geologic success. The value compares with the industry perception of about a 5% chance of success on an exploration well.

Fekete has also successfully used a five-parameter system to estimate the

probability of geologic success as follows:

$$P_g = P_{\text{source}} * P_{\text{reservoir}} * P_{\text{structure}} * P_{\text{seal}} * P_{\text{migration}}$$

Note that the individual subscripts can be customized to suit each evaluation. A neutral (50%) assignment for all 5 factors yields an overall chance of geologic success of 3.125%.

In Fekete's experience, either a four- or five-parameter system can be used to evaluate a prospect. Which to use often comes down to which the earth science team that is doing the evaluation is most comfortable with. Fekete has also evaluated prospects with a seven-parameter system (CCOP, July 2000) but when all seven parameters have a neutral (0.5) rating, the chance of geologic success is 0.8%. This does not mean that a seven-parameter system should not be used, but when it is, the evaluators must be aware of the consequence of additional multiplication and adjust the input values relative to the values that would have been used in a four- or five-factor evaluation.

A five-factor system was used for Geologist B's prospect and values estimated as shown in Table 11.6.

Parameter	Probability
Source Rock	45%
Migration Path (Timing)	90%
Structure	90%
Seal (Cap) Rock	81%
Reservoir Rock	40%
Probability of Geologic Success	12%
Probability of Dry Hole	88%

Table 11.6. Five-factor system parameters.

A 12% chance of success means there is an 88% chance of a dry hole on the first drilling attempt. If the drilling sequence is a random series of events, as the number of consecutive drilling attempts increases, the chance that they will all be dry holes decreases. Table 11.7 shows the profile, assuming random events.

No of Drills	Chance they are all dry holes	Chance of at least one discovery
1	88%	12%
2	78%	22%
3	69%	31%
4	60%	40%
5	53%	47%
6	47%	53%
7	41%	59%
8	37%	63%
9	32%	68%
10	28%	72%

Table 11.7. Chance of Failure / Success.



In reality, we should learn something about the prospect and play with each drilling attempt, so we may consider that less than 10 wells are required for a 70% chance of making at least one discovery. Or we may decide that the drilling locations currently available to the company are not related and the above table reasonably presents the chance with each successive attempt.

The consensus for Geologist B was that even with luck, a minimum of three dry holes would be incurred before making a discovery. The more likely value was six (53% chance of a discovery) but up to ten attempts could be required to tip the odds in the company's favour. An additional \$10 MM was also recommended for additional seismic acquisition (Table 11.8).

Item	Low	Medium	High
Number of Dry Holes	3	6	10
Per Dry Hole Cost	0.7	0.8	1.0
Seismic Data		10	

Table 11.8. Exploration Costs (all values in millions of dollars).

From Monte Carlo simulation, total dry hole costs, total exploration costs, and cumulative

	P10	P50	P90
Total Dry Hole Costs	3	5.3	7.9
Seismic Data	10	10	10
Total Exploration Costs	13	15.3	17.9
Exploration + Development Costs	44.8	52.4	60.7

Table 11.9. Cumulative Prospect Capital Cost Ranges.

prospect capital cost ranges were estimated as shown in Table 11.9:

With a total exploration and development cost of \$60.7 MM and a PV before investment value of \$62 MM at the 90th percentile (Figure 11.3), the prospect has better than a 90% chance of achieving a positive NPV (if the deposit really exists). When presented with this level of economic attractiveness, most companies would seriously consider pursuing Geologist B's prospect.

#### PROSPECT FINANCIAL COMPARISONS

Figure 4 summarizes the financial "picture" for Geologist A's development prospect. Figure 5 presents Geologist B's exploration prospect. The Max NPV curve is generated by subtracting the P10 total cost value from the NPV before capital curve. The Min NPV curve is similarly created from the NPV before capital curve less the P90 value for total capital costs.

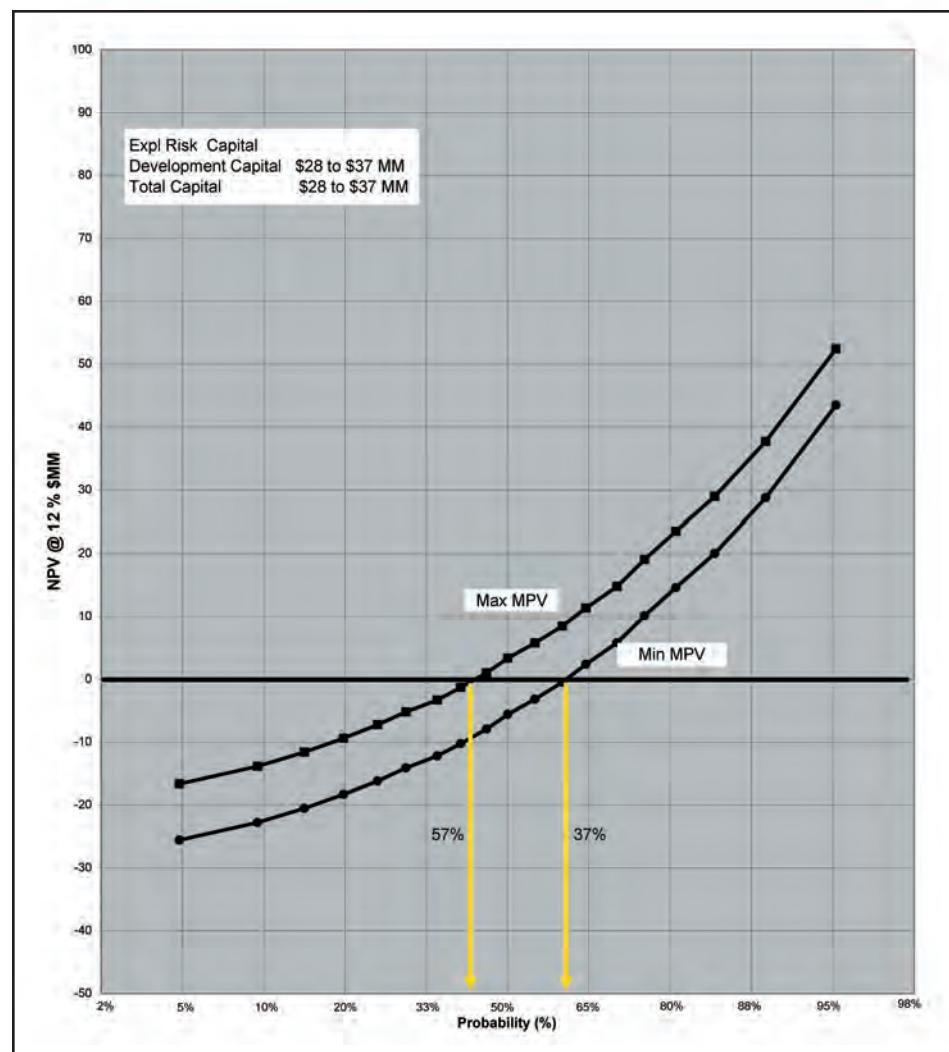


Figure 11.4. Gas development prospect NPV.

The chance of realizing a positive NPV on the capital investment can be read from the graph. From Figure 11.4, upper and lower limits of the NPV curve have a value of zero at about the 43rd and 63rd percentiles. The chance of achieving a positive NPV on the capital investment with Geologist A's development prospect is between 37 and 57%.

In Figure 11.5, the  $NPV = 0$  axis is intersected at about the 6th and 9th percentiles. If Geologist B's exploration interpretation is correct, there is between a 91 and 94% chance of achieving a positive NPV on the capital investment.

For any prospect, management needs to know:

- The chances that at least the value of the capital investment will be recovered if the project proceeds.
- How much capital could be lost if events do not turn out as expected.

- The potential gain in economic value if events do unfold as expected.
- total capital commitment required to realize production.

Which prospect would you invest in?

#### REFERENCES

Canadian Institute of Mining, Metallurgy and Petroleum. 1994. Determination of Oil and Gas Reserves, Petroleum Society Monograph Number 1, Chapter 6.

Canadian Institute of Mining, Metallurgy and Petroleum. 2004. Determination of Oil and Gas Reserves, Petroleum Society Monograph Number 1, Chapter 6.

Coordinating Committee for Coastal and Offshore Geoscience Programmes in East and Southeast Asia (CCOP). 2000. The CCOP Guidelines for Risk Assessment of Petroleum Prospects. July, 2000. 35 p.



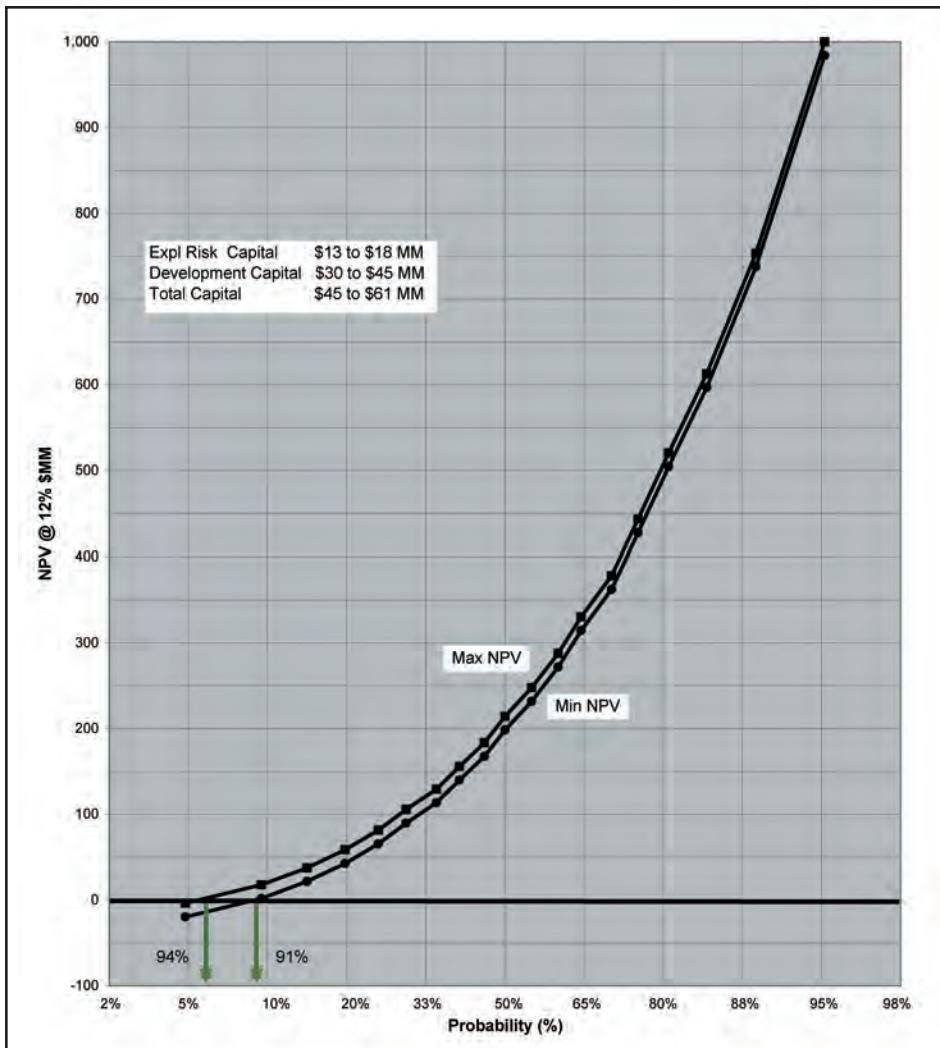


Figure 11.5. Oil exploration prospect NPV potential.

Dean, L. 2008. Reservoir Engineering For Geologists, Part 3: Volumetric Estimation. Canadian Society of Petroleum Geologists Reservoir, v. 34, no. 11, p. 20-23.

Mireault, R. and Dean, L. 2008. Reservoir Engineering For Geologists, Part 8b: Monte Carlo Simulation / Risk Assessment. Canadian Society of Petroleum Geologists Reservoir, v. 35, no. 7, p. 14-19.

Otis, Robert M. and Schneidermann, Nahum. 1997. A Process for Evaluating Exploration Prospects. AAPG Bulletin, vol. 81 no. 7. p. 1087-1109



# Reservoir Engineering for Geologists

## Article 12 - Coalbed Methane Fundamentals

by Kamal Morad, P. Eng., Ray Mireault, P. Eng., and Lisa Dean, P. Geol., Fekete Associates Inc.

Historically, gas emissions from coal have been a nuisance and a safety hazard during coal mining operations, causing numerous explosions and deaths. But today, coalbed methane (CBM) is an increasingly important source of the world's natural gas production with many countries, including Canada, actively developing this unconventional energy source.

Currently, CBM accounts for 10% of U.S. natural gas production with the size of the resource (OGIP) estimated at 700 TCF. The most active areas of production are the San Juan Basin in New Mexico, the Powder River Basin in northeast Wyoming / southeast Montana, and the Black Warrior Basin in Alabama.

In Canada, CBM is still in the early stages of development, yet it already accounts for about 1% of total gas production. The Western Canada Sedimentary Basin contains the majority of Canada's estimated 600 TCF of CBM resource potential. Formations of greatest interest are the Mannville, which tends to produce water as well as gas (a "wet" coal) and the Horseshoe Canyon, which usually produces gas with virtually no water (a "dry" coal).

In general, coal is classified into four main types depending on the quantity and types of carbon it contains as well as the amount of heat energy it can produce. These are:

1. Lignite (brown coal) – the lowest rank of coal; used as fuel for electric power generation.
2. Sub-bituminous coal – properties range between lignite and bituminous coal.
3. Bituminous coal – a dark brown to black, dense mineral; used primarily as fuel in steam-electric power generation.
4. Anthracite – the highest rank; a harder, glossy, black coal used primarily for residential and commercial space heating; it may be divided further into petrified oil, as from the deposits in Pennsylvania.

Note that graphite, which is metamorphically altered bituminous coal, is technically the highest rank of coal. However, it is not commonly used as fuel because it is difficult to ignite.

### COAL CHARACTERISTICS

Coals are recognized on geophysical logs

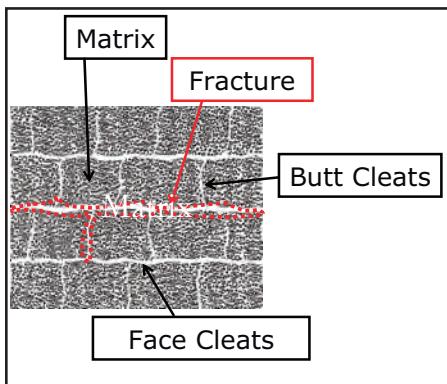


Figure 12.1. Coal is a dual-porosity system.

because of several unique physical properties. The coals typically have very low gamma, low density, and high resistivity values.

Similar to conventional naturally fractured reservoirs, coal is generally characterized as a dual-porosity system because it consists of a matrix and a network of fractures (Figure 12.1). For both groups, the bulk of the in-place gas is contained in the matrix. However, matrix permeability is generally too low to permit the gas to produce directly through the matrix to the wellbore at significant rates.

In a naturally fractured system, most of the produced gas makes its way from the matrix to the fracture system to the wellbore. If the well has been hydraulically frac'd, gas may also travel from the natural fracture system to the man-made fracture system to the wellbore. With both conventional naturally fractured reservoirs and CBM reservoirs, the natural fracture system has high permeability,

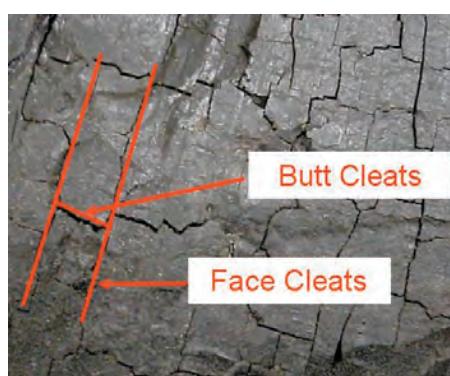


Figure 12.2. Example of coal cleat structure.

relative to matrix permeability, but very limited storage capacity.

In coal terminology, natural fractures are called "cleats". The cleat structure consists of two parts: face cleats and butt cleats (Figure 12.2). Face cleats are typically continuous fractures that go across the reservoir. They are considered the main pathway for gas production.

Butt cleats are discontinuous, perpendicular to the face cleats and generally act as a feeder network of gas into the face cleats.

The effective porosity, permeability, and water saturation are all properties of the coal "cleat" system. Since coal permeability is a property of the cleat space, it is affected by the structure and characteristics of the cleat network, e.g., the dominant fracture orientation, fracture continuity, frequency, and width.

The effective permeability of the cleat system is also influenced by the contrast between face and butt cleat permeability. CBM reservoirs are generally considered to be anisotropic systems, where the effective permeability is the geometric average of face and butt cleat permeability. Permeability anisotropy creates elliptical drainage areas and should be taken into account when placing wells in CBM development projects.

### DIFFERENCES WITH CONVENTIONAL RESERVOIRS

A good starting point to understanding the production characteristics of coalbed methane reservoirs is by considering the differences to conventional gas production. The most significant differences are:

- In a conventional reservoir, the majority of the gas is contained in the pore space but in a CBM reservoir, the majority of the gas is adsorbed (bonded to the coal molecules) in the matrix.
- In a conventional reservoir, reservoir gas expands to the producing wells in direct response to any production-induced pressure gradient. But CBM reservoirs generally require that reservoir pressure be below some threshold value to initiate gas desorption.
- In a CBM reservoir, a gas molecule must first desorb and diffuse through the coal matrix to a cleat. It can then move

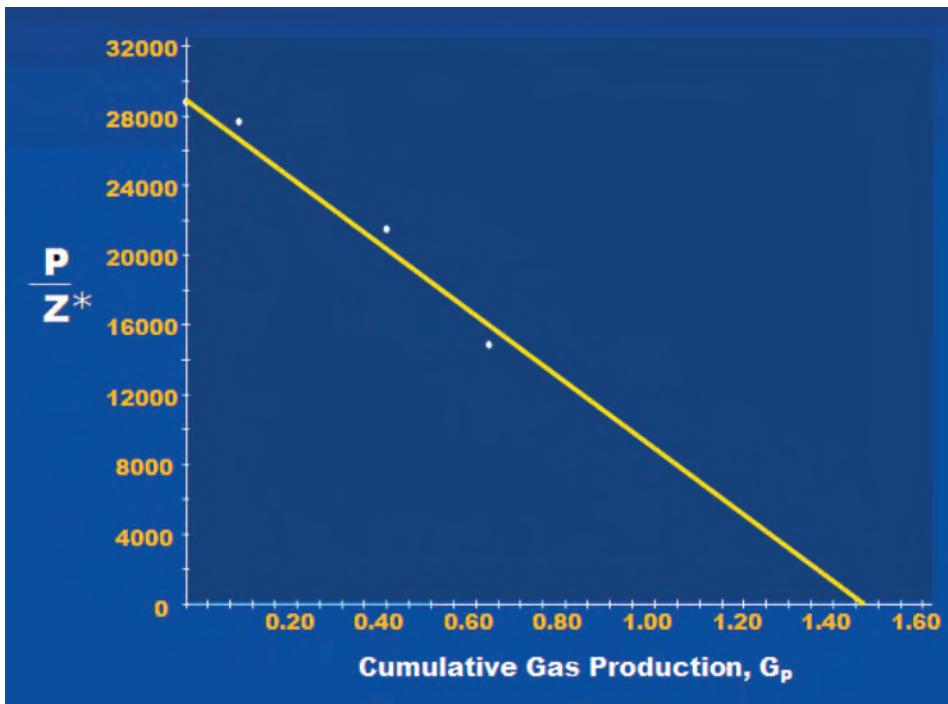


Figure 12.3. Conventional gas P/Z plot.

through the cleated fracture system and the hydraulic frac-stimulation to the wellbore via conventional Darcy flow.

#### CBM GAS STORAGE CAPABILITY

The primary storage mechanism in CBM reservoirs is adsorption of gas by the coal matrix. Matrix surface area, reservoir pressure, and the degree to which the coal is gas saturated are the factors that determine the in-place gas volume of a coal. Note that the smaller the coal particle size, the larger the surface area.

The complete gas-in-place volumetric equation for a CBM reservoir is:

$$OGIP = A * h * \rho_b^* GC_i + (Ah\phi(1-Sw_i) / B_{gi})$$

Where:

- A is drainage area,
- h is net pay,
- $\rho_b^*$  is bulk density,
- $GC_i$  is initial Gas Content,
- $\phi$  is porosity,
- $Sw_i$  is initial water saturation
- $B_{gi}$  is initial formation volume factor.

The first term represents the adsorbed gas in the matrix while the second term is the free gas in the cleats. Since the pore volume in CBM reservoirs is in the order of 1% of the total volume, the free gas contribution to the total in-place gas volume is negligible.

As with all volumetric estimates, uncertainty in the input data creates a range of possible outcomes for OGIP. Some common areas of uncertainty for CBM projects include:

- The gas content of the coal,
- The degree of heterogeneity and complexity contained in CBM reservoirs,
- The impact of modelling complex multilayer coal/non-coal geometries with simple one- or two-sequence models.

#### CBM GAS DESORPTION

While the relationship between pressure decline and gas production is essentially a straight line in a conventional reservoir (Figure 12.3), the depletion profile in a CBM reservoir is distinctly non-linear. For a given pressure drop, a CBM reservoir will desorb significantly more gas when the starting reservoir pressure is low compared to when reservoir pressure is high (Figure 12.4).

If the initial reservoir pressure is significantly greater than the pressure required to initiate desorption (the coal is under-saturated), and water is initially present in the cleat system, then the initial production period may produce only water without any gas (Figure 12.5). Depending on the degree of undersaturation, dewatering can last from a few months to two or three years and can significantly affect the economics of the prospect.

If initial reservoir pressure is equal to the critical desorption pressure (the coal is gas-saturated), then gas production will start as soon as reservoir pressure begins to decrease. This situation most often applies to "dry" coals but can also apply to saturated "wet" coals.

The equation that is commonly used to describe the relationship between adsorbed gas and free gas as a function of pressure is known as the Langmuir isotherm. The isotherm is determined experimentally and measures the amount of gas that can be adsorbed by a coal at various pressures. The Langmuir isotherm is stated as:

$$V = V_L * (P / P_L + P)$$

Where:

- $V_L$ , the Langmuir Volume, is the gas content of the coal when reservoir pressure approaches infinity.

- $P_L$ , the Langmuir Pressure, is the pressure corresponding to a gas content that is half ( $\frac{1}{2}$ ) of the Langmuir volume. The steepness of the isotherm curve at lower pressures is determined by the value of  $P_L$ .

CBM gas consists primarily of methane ( $CH_4$ ) but may also contain lesser percentages of carbon dioxide ( $CO_2$ ) and nitrogen ( $N_2$ ). As coal has the strongest affinity for nitrogen

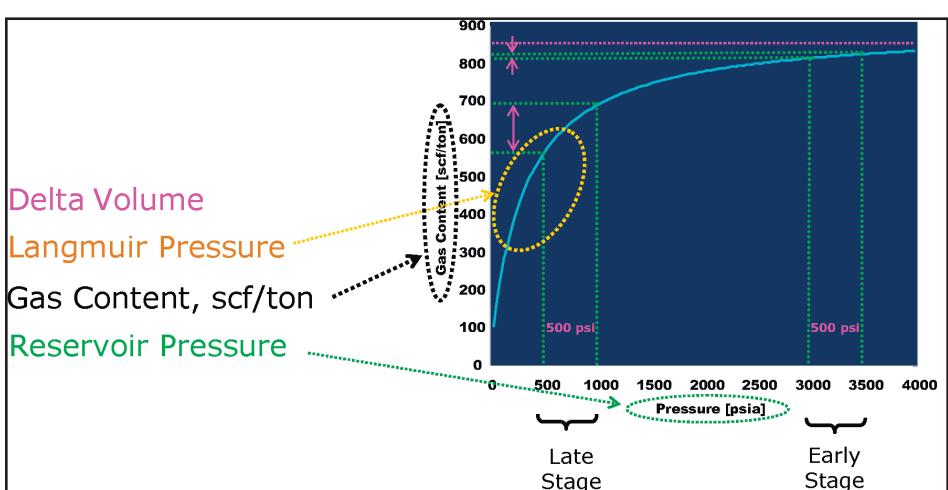


Figure 12.4. Comparison of desorption volumes with changes in reservoir pressure.



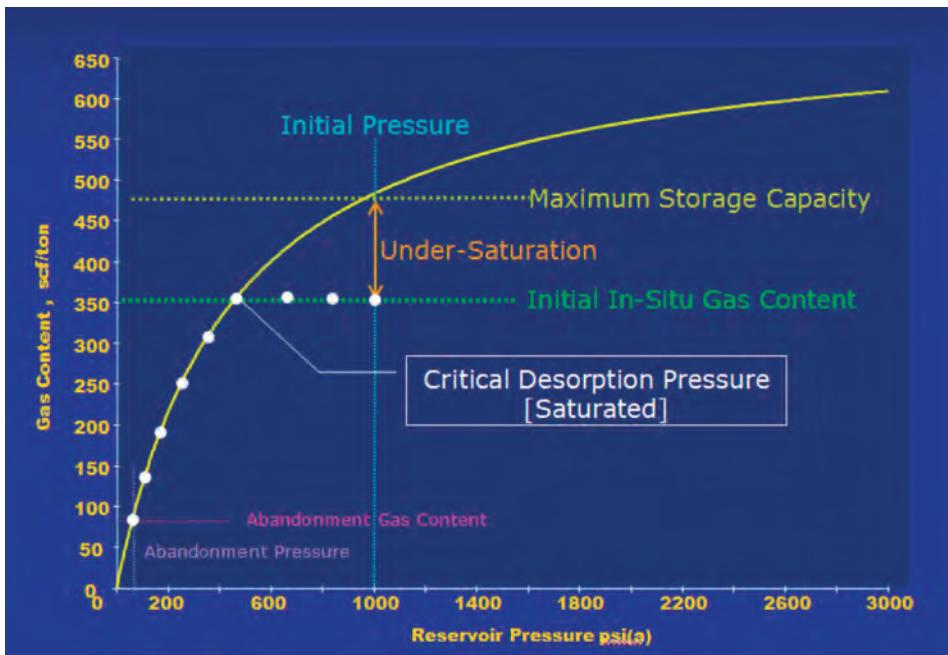


Figure 12.5. Desorption behaviour of under-saturated CBM reservoirs.

and the weakest affinity for carbon dioxide, the three gases adsorb/ desorb at different rates from coal (Figure 12.6). Thus, it is not uncommon for the  $\text{CO}_2$  content of the produced gas to decrease as gas is produced and reservoir pressure depletes.

#### CBM GAS TRANSPORT MECHANISMS

After desorbing from the coal, gas in a CBM reservoir uses diffusion to travel through the coal matrix to the cleat system. The time required to diffuse through the matrix to a cleat is controlled by the gas concentration gradient, the gas diffusion coefficient, and the

cleat spacing. In general, greater concentration gradients, larger diffusion coefficients, and tighter cleat spacing all act to reduce the required travel time. On reaching a cleat, gas then travels the remaining distance to the wellbore by conventional Darcy flow. Since flow in a CBM reservoir is generally two-phase flow, fluid saturation changes in the cleat system and consequent changes in relative permeabilities become important.

As the gas is produced from a CBM reservoir, two distinct and opposing phenomena occur

that affect the absolute permeability of the cleat system:

1. As reservoir pressure decreases, it reduces the pressure in the cleats. Cleat effective stress (which is the difference between overburden stress and pore pressure) increases and compresses the cleats, causing cleat permeability to decrease.
2. As gas desorbs from the coal matrix, the matrix shrinks. Shrinkage causes the space within the cleats to widen and the permeability of the cleats increases. From the Langmuir isotherm (Figure 12.4), the amount of gas desorbed for a given pressure drop is relatively small at high pressures. Thus in the early stages of production, the compaction effect is the dominant factor and cleat permeability will tend to decrease slightly. As production continues and gas recovery becomes significant, matrix shrinkage will dominate and increase cleat permeability.

In “wet” coals, changes in the relative permeability of the cleat system with changes in water and gas saturation must be considered in the Darcy flow equation to correctly predict well performance. As illustrated by a typical set of relative permeability curves (Figure 12.7), the relative permeability to gas increases with decreasing water saturation and vice versa.

#### CBM WELL PERFORMANCE

The production of CBM wells can be generally divided into three separate phases (Figure 12.8):

- Dewatering phase (for under-saturated reservoirs): In this phase, no gas is produced (excepting in the transient near wellbore region or in complex reservoirs).
- Negative decline: Water production continues to decline while gas production increases.
- Production in this phase is generally dominated by the relative permeability of gas and water.
- Decline phase: Declining reservoir pressure is now the dominating factor although its impact is mitigated to some extent by a shrinking matrix and increasing cleat permeability. Nonetheless, the gas production rate declines as in conventional gas reservoirs, albeit at a slower rate of decline.

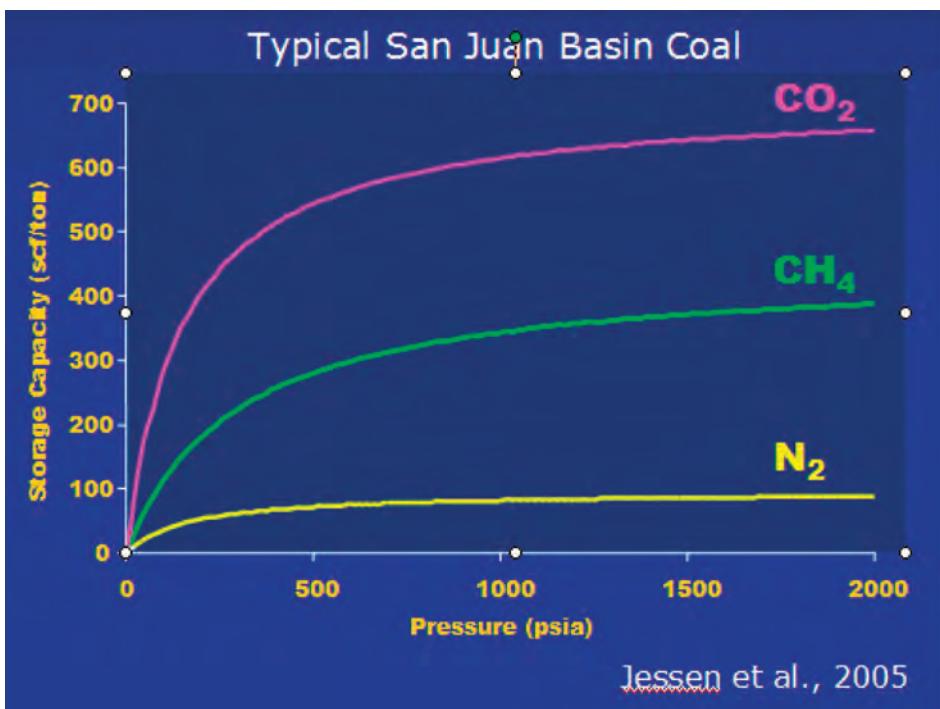


Figure 12.6. CBM gas storage capacities for  $\text{N}_2$ ,  $\text{CH}_4$ , and  $\text{CO}_2$ .

The water production forecast looks similar to a production forecast for a conventional water producing reservoir. Maximum water production rates are achieved initially but decline thereafter through a combination of

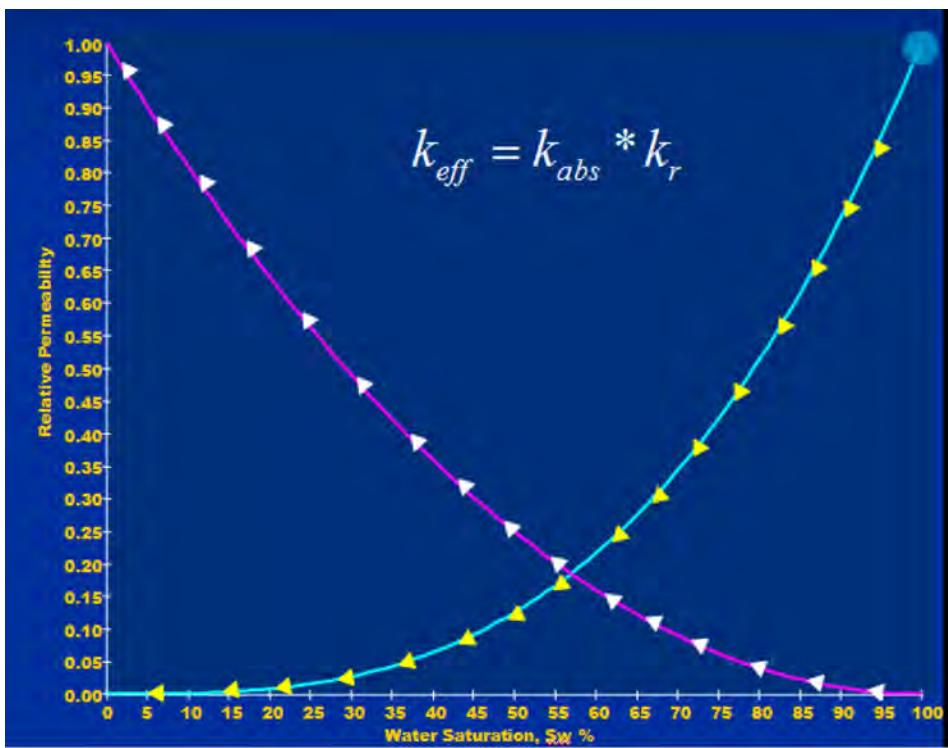


Figure 12.7. Relative permeability to gas and water.

reservoir pressure depletion and decreasing relative permeability to water.

The gas production profile displays both the initial, dormant period followed by an increasing production rate till it reaches a peak and then declines. Although reservoir pressure is monotonically declining through the life of the simulation well, it is counteracted during the inclining production period by increases in the relative permeability to gas and in the absolute permeability of the cleats.

As the water saturation approaches its minimum value, declining reservoir pressure dominates and the well goes into the decline phase of its producing life. During this time period, the declining production trend resembles conventional gas production. Note that a "dry" CBM reservoir exhibits only the declining portion of the production pattern.

Given the scope and complexity of the inputs for CBM reservoirs, simulation is generally required to predict the deliverability and

cumulative production of CBM wells. As improvements in drilling, completion and production techniques advance, CBM will continue to be an increasingly important source of natural gas.

#### REFERENCES

Gas Research Institute. 1993. GRI Reference No. GRI-94/0397, "A Guide to Coalbed Methane Reservoir Engineering," Chicago, Illinois.

Jensen, D. and Smith, L.K. 1997. A Practical Approach to Coalbed Methane Reserve Prediction Using a Modified Material Balance Technique. International Coalbed Methane Symposium, The University of Alabama, Tuscaloosa, Alabama, paper 9765, p. 105-113.

Lamarre, Robert A. 2005. "Coalbed Methane – A Non-Conventional Energy Source What Is It And Why Is It Important," 25th Annual North American Conference of the USAEE/IAEE, Fueling the Future.

Mavor, M.J. 1996. A Guide to Coalbed Methane: Coalbed Methane Reservoir Properties. Gas Research Institute Chicago, Illinois, GRI Reference No. GRI-94/0397, Chapter 4.

Schafer, P.S. and Schraufnagel, R.A. 1996. A Guide to Coalbed Methane: The Success of Coalbed Methane. Gas Research Institute Chicago, Illinois, GRI Reference No. GRI- 94/0397, Chapter 1.

Steidl, P.F. 1996. A Guide to Coalbed Methane Reservoir Engineering: Coal as a Reservoir. Gas Research Institute Chicago, Illinois, GRI Reference No. GRI-94/0397, Chapter 2.

Zuber, M.D. 1996. A Guide to Coalbed Methane: Basic Reservoir Engineering for Coal. Gas Research Institute Chicago, Illinois, GRI Reference No. GRI-94/0397, Chapter 3.

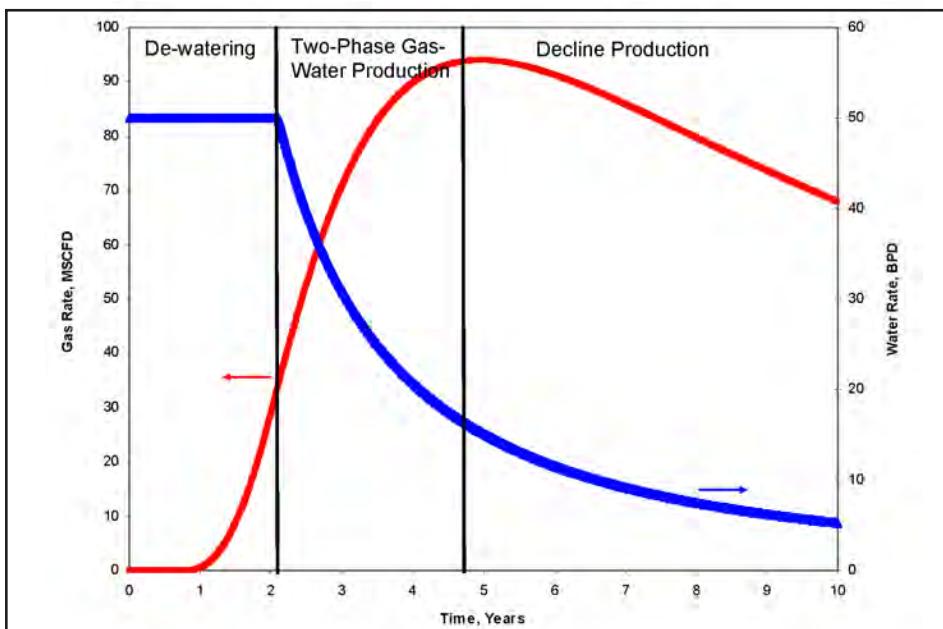


Figure 12.8. CBM well production profile.

**Fekete**



# Reservoir Engineering for Geologists

## Article 13 - Geological Storage of CO<sub>2</sub>

by Mehran Pooladi-Darvish, Ph.D., P. Eng. and R. Mireault, P. Eng., Fekete Associates Inc.

Over the past few years, the production and usage of fossil fuels has increased despite rising concern over the atmospheric emission of greenhouse gases (e.g., CO<sub>2</sub>). It appears that fossil fuels will remain the energy of choice for at least a few more decades. Despite conservation, alternate fuels, constrained supply, and higher prices, the National Energy Board predicts that the demand for fossil fuels in Canada will continue to increase. The International Energy Agency forecasts similar trends for worldwide demand at least until 2050.

This article does not debate either the occurrence of global warming or the role played by man-made CO<sub>2</sub> emissions. It instead considers the similarities and differences between hydrocarbon production and the geological storage of CO<sub>2</sub>. Assuming the public is interested in capturing the CO<sub>2</sub> waste created by burning fossil fuels, Alberta is a suitable place for its geological storage and the petroleum industry has the necessary abilities to significantly reduce net CO<sub>2</sub> emissions.

### CO<sub>2</sub> Emissions in Canada and Alberta

In 2000, Canada's CO<sub>2</sub> emissions were approximately 725 megatonnes (Mt) (Figure 13.1). Alberta and Ontario together accounted for 430 Mt or slightly less than 60% of total emissions. Quebec, British Columbia, and Saskatchewan together accounted for 220 Mt or about 30%.

How much gas is this? In petroleum industry

terms, 230 Mt/yr (Alberta's annual emissions) translates to approximately 12 bcf/d; roughly equal to Alberta's daily natural gas production rate. Conversely, injecting 12 bcf/d of CO<sub>2</sub> would require 400 wells, each operating at 30 mmcf/d.

While all generated CO<sub>2</sub> presents equal potential in terms of the greenhouse gas effect, the level of effort needed to collect, purify, and inject CO<sub>2</sub> varies with the source of the emission. For example, CO<sub>2</sub> from large stationary point sources, such as coal-fired power plants and hydrocarbon processing plants, is more easily captured and stored compared to CO<sub>2</sub> from small, moving sources such as automobiles.

Note that fossil fuels contribute to CO<sub>2</sub> emissions both when they are produced (e.g., oil sand production, bitumen upgrades, and gas-sweetening plants) and when they are burned. Capture refers to the process of selectively treating or purifying the waste gas stream to "capture" just the CO<sub>2</sub> component for injection (e.g., flue gas contains less than 15% CO<sub>2</sub>).

While the majority of CO<sub>2</sub> emissions in Ontario are from small emitters, about half of the total emissions in Alberta are from large, point-source stationary plants. Given the abundance of depleting petroleum reservoirs in the Western Canada Sedimentary Basin, capture and geological storage would appear to be the preferred solution, at least for Alberta's point sources

of CO<sub>2</sub>.

The sheer magnitude of a 6 bcf/d injection rate raises additional considerations. Further, a multi-century time-scale for the geological storage of CO<sub>2</sub> is a fundamental departure with the decade(s)-long operating horizon for hydrocarbon development (Bachu, 2008a). To address these differences, the models and workflows used for hydrocarbon development are being reconsidered and revised.

### Desired Storage Site Characteristics

A desired CO<sub>2</sub> storage site should have at least the following characteristics:

- Ensure containment over long periods of time (centuries).
- Enough injectivity to receive the CO<sub>2</sub> at the desired rates.
- Sufficient storage capacity.

### Containment

The density of CO<sub>2</sub> increases with increasing depth / pressure, to approximately 700 kg/m<sup>3</sup> at 2,000 to 3,000 m. But the density of formation brines is above 1,000 kg/m<sup>3</sup>. As with petroleum reservoirs, competent cap rock is required to ensure containment. Even with competent cap rock, creating large, buoyant accumulations of concentrated CO<sub>2</sub> that are in storage for centuries raises complex questions. Therefore, natural and man-made processes are being studied that could lead to permanent trapping of the injected CO<sub>2</sub>. For example:

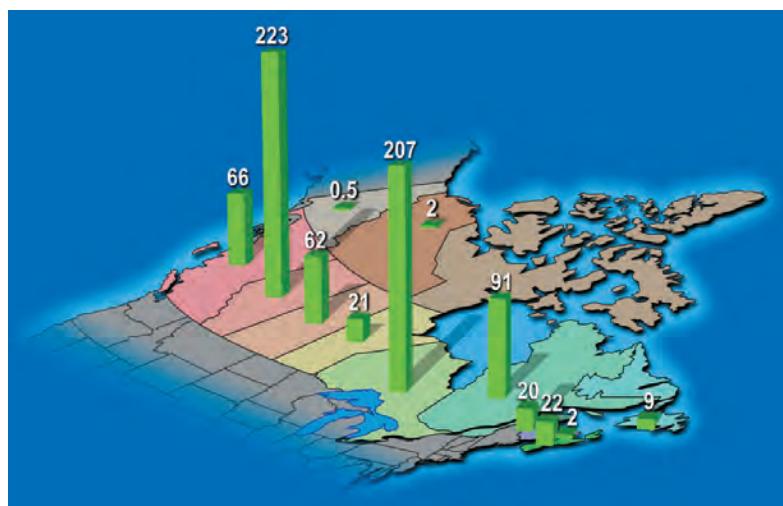


Figure 13.1. CO<sub>2</sub> emissions (Mt / year) in Canada in 2000 (Bachu, 2008b).

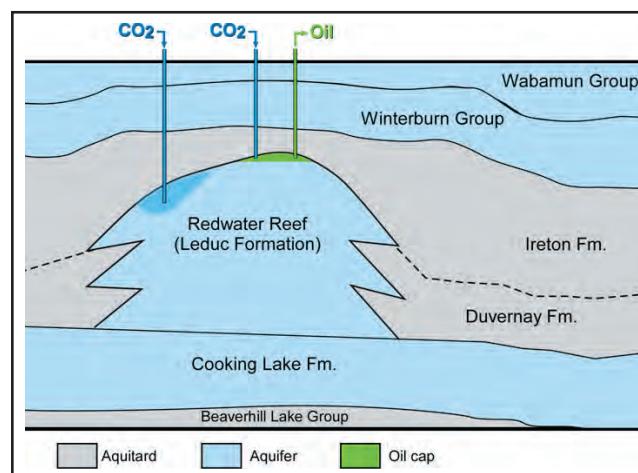


Figure 13.2. Large-scale CO<sub>2</sub> storage in the Redwater Reef (Gunter and Bachu, 2007).

- Designs are being considered to enhance the contact between CO<sub>2</sub> and the formation brine, to facilitate what is called “solubility trapping.” Once CO<sub>2</sub> is dissolved in the brine, the mixture is denser than the in-situ brine and tends to settle.

- Reacting CO<sub>2</sub> with formation minerals could create new stable minerals – “mineral trapping.”

- After flowing through porous rock, small CO<sub>2</sub> bubbles can remain trapped in the

pore space by capillary forces – “residual trapping.”

While many of these trapping processes occur naturally, they occur slowly over centuries. To accelerate these trapping mechanisms, engineering solutions are being proposed. For example:

- In a dipping aquifer, down-dip injection of CO<sub>2</sub> could lead to CO<sub>2</sub> flow underneath the cap rock and along the length of the aquifer, enhancing solubility trapping. The reduced risk of

leakage as a result of enhanced solubility trapping will need to be balanced against the increased risk of leakage with distance from the injection site, since our knowledge of the integrity and areal extent of the cap rock generally decreases with distance from the well.

- Studies conducted by Hassanzadeh et al. (2008) suggest that production of the formation brine farther away from the CO<sub>2</sub> injection site and its injection on top of the CO<sub>2</sub> plume at some distance from the CO<sub>2</sub> injector, could lead to solubility trapping of a significant amount of CO<sub>2</sub> at a small energy cost.

### Injectivity

Although total injection rates can always be increased by drilling more injection wells, the number of wells that will ultimately be required to inject 6 bcf/day can significantly affect the economics of geological storage. High permeability reservoirs and formations are obviously preferred.

Fekete's studies have shown that the CO<sub>2</sub> injection rate is not only controlled by permeability in the vicinity of the wellbore but also by the permeability distribution throughout the reservoir. The  $k_v/k_h$  relationship is equally important with respect to overall storage capacity of the formation. For example, in simulation studies of the Redwater reef, the allowable injection rate is strongly affected by the degree of communication / permeability between the margins of the reef, the interior of the reef, and the underlying Cooking Lake aquifer.

Evaluating the permeability distribution throughout a reservoir is not normal practice when injecting petroleum wastes at modest rates. Nonetheless, it is required to assess the dissipation of the resulting pressure build-ups (below fracture gradient) at the rates required for large scale CO<sub>2</sub> injection. Thus, additional geology / geophysics / drilling / testing may be required to develop the degree of characterization necessary for detailed planning of CO<sub>2</sub> projects.

### Capacity

Depleted oil and gas pools are attractive as storage sites, because of the availability of information and the knowledge that the cap rock is a competent seal. But large scale CO<sub>2</sub> injection, (6 bcf/d is 2.2 tcf/year) requires formations that can store 10's of tcf or 1,000+ megatonnes of CO<sub>2</sub>. While depleted petroleum pools may play a part in localized injection of CO<sub>2</sub>, two projects that are being considered for Alberta, illustrate the differences between conventional



Figure 13.3. Redwater's proximity to large CO<sub>2</sub> emitters (Gunter and Bachu, 2007).



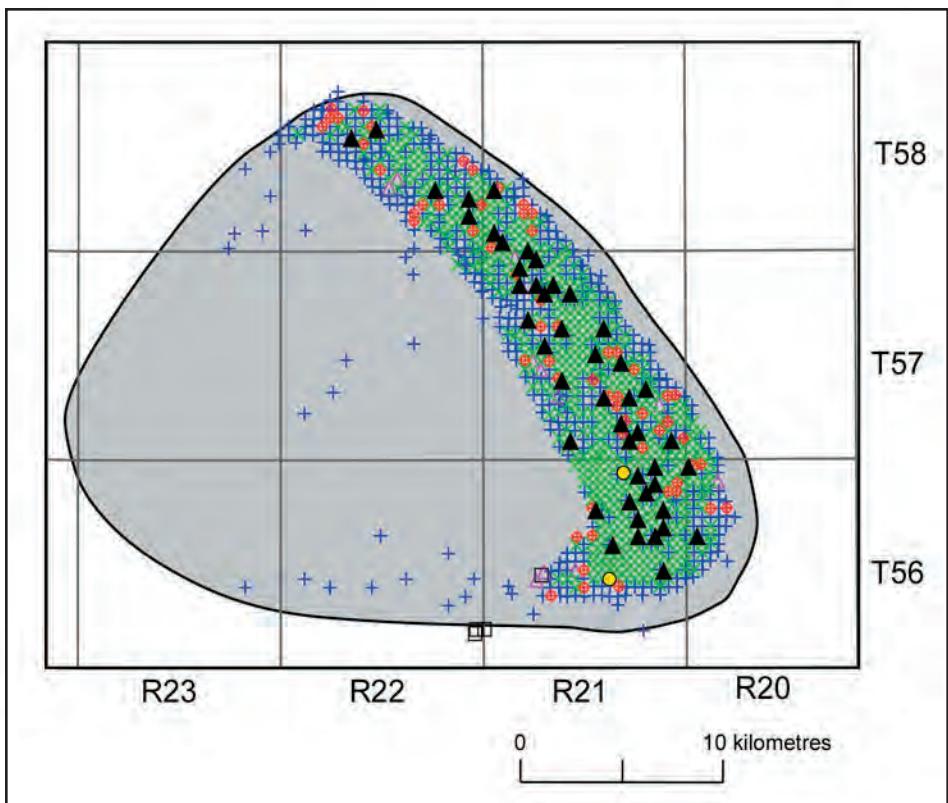


Figure 13.4. Redwater well locations (Gunter and Bachu, 2007).

hydrocarbon production and large-scale geological CO<sub>2</sub> storage operations.

#### HARP

The Heartland Area Redwater Project (HARP), run by Alberta Research Council and industrial partner ARC Resources, envisions using the entire Redwater reef as a CO<sub>2</sub> storage site. The Redwater oil reservoir was the third-largest oil field in Alberta but it occupied only a small fraction of the total reef volume (Figure 13.2). The factors that led to the selection of Redwater for large scale CO<sub>2</sub> storage are:

- Its proximity to several large CO<sub>2</sub> emitters: the Heartland industrial area (northeast of Edmonton) and the CO<sub>2</sub> that may be pipelined from oil sands production facilities in the Fort McMurray area (Figure 13.3).
- Established knowledge of the reef's containment geometry, capacity, and injectivity – albeit over a small portion of the reef.

One of the challenges to the project is the lack of geoscience knowledge over large portions of the reef, which nevertheless is required for storage. While hundreds of wells have been drilled in the northeastern portion of the reef (most to shallow depths) the rest of the reef has been penetrated by only a couple of dozen wells (Figure 13.4).

The reef and its overlying and underlying strata are being characterized, using available geological, petrophysical, geophysical, hydrogeological, and engineering information. Initial studies have been conducted to estimate storage capacity, number, and location of injection wells, and fate of the injected CO<sub>2</sub> in the reservoir. These will be refined as exploratory well(s) are drilled and a pilot project is conducted, monitored, and evaluated.

#### WASP

The Wabamun area CO<sub>2</sub> Sequestration Project (WASP), run by the University of Calgary and Industrial Partners, is investigating aquifer disposal for four coal-fired power plants west of Edmonton that contribute significantly to Alberta's CO<sub>2</sub> emissions (Figure 13.5).

Michael et al. (2008) have reviewed the CO<sub>2</sub> storage potential of different formations that are in close proximity to the power plants, mapping at least three sequences of aquifers (Figures 13.6). The dolomitized Nisku aquifer is separated from the surface by at least two sequences of seals (shales) and appears to potentially meet the three requirements of containment, capacity, and injectivity. Studies similar to those planned for HARP are underway.

#### From where we are to where we need to be

Making a significant impact on the net volume of CO<sub>2</sub> emissions, even from Alberta's 2002 rate of 12 bcf/d, requires a large industry. The petroleum industry, with its earth-science and engineering knowledge, its operating expertise, managerial ability, and financial resources, is well suited to the task of CO<sub>2</sub> capture and geological storage. We already know much about the issues by virtue of our hydrocarbon production experience:

- The same formations and knowledge that have produced hydrocarbons from the Western Canada Sedimentary Basin are required for CO<sub>2</sub> injection and storage. Further, working in concert provides the potential for co-optimization of hydrocarbon production and CO<sub>2</sub> injection.
  - The industry is familiar with the challenges posed by surface transport of large fluid volumes and their underground injection and monitoring.
  - For more than two decades, dozens of acid gas disposal projects, many having CO<sub>2</sub> as the main constituent of the gas, have been underway in Alberta. These projects have much that is of direct application to the geological storage of CO<sub>2</sub> (Pooladi-Darvish et al., 2008).
- There are differences and significant challenges ahead:
- The injection rate and volumes for the acid gas disposal projects have been much smaller than the scale of CO<sub>2</sub> storage projects that will significantly affect the net volume of CO<sub>2</sub> emissions.
  - Hydrocarbon sweetening operations have been the CO<sub>2</sub> source for acid gas

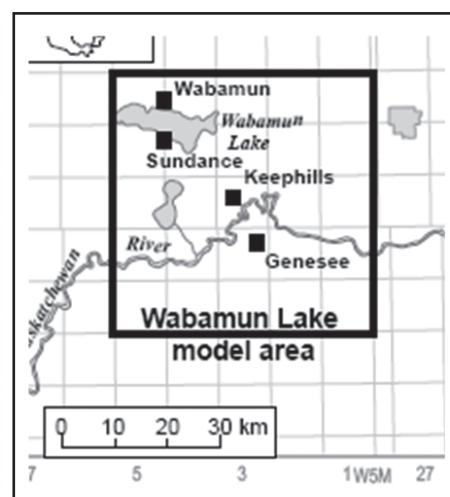


Figure 13.5. Large coal-fired CO<sub>2</sub> emitters near Edmonton (Mitcheal et al., 2008).

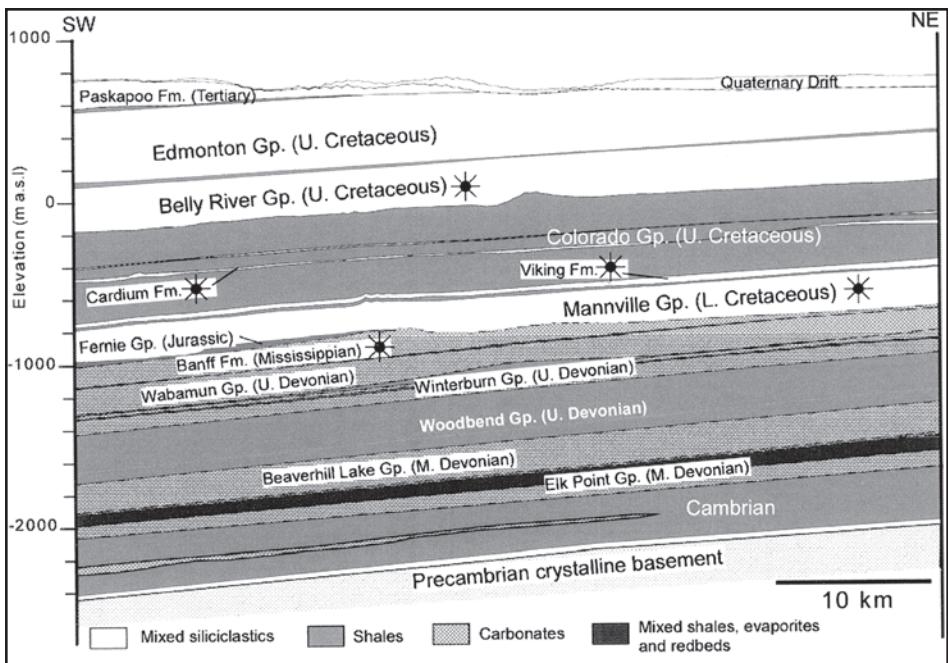


Figure 13.6. Wabamun area stratigraphic chart (Mitcheael et al., 2008).

disposal projects. But large-scale geological storage projects will mostly capture CO<sub>2</sub> from the burning of fossil fuels, such as from coal-fired power plants. The different effluent gas composition from power plants may require different technologies to capture and purify the CO<sub>2</sub> component in the emissions.

- While smaller CO<sub>2</sub> projects could potentially make use of depleted oil and gas pools, there is a point where only aquifers can provide sufficient storage capacity. But our present knowledge of aquifer extent, quality, and distribution – even those associated with hydrocarbon production – is likely insufficient for large scale CO<sub>2</sub> storage.

Capture and geological storage of CO<sub>2</sub> presents both challenges and opportunities. As Figure 13.7 illustrates, the industry is on a steep learning curve.

#### References :

Bachu, S. 2008a. CO<sub>2</sub> Storage and Geological Media: Role, means, status, and barriers to deployment. Progress in Energy and Combustion Science – An International Review Journal, v. 34, p. 254-273.

Bachu, S. 2008b. personal communications.

Gunter, W. and Bachu, S. 2007. The Redwater Reef in the Heartland Area: A Unique Opportunity for Understanding and Demonstrating Safe Geological Storage of CO<sub>2</sub>. [http://www.nrcan.gc.ca/es/etb/cetc/combustion/co2network/htmldocs/publications\\_e.html](http://www.nrcan.gc.ca/es/etb/cetc/combustion/co2network/htmldocs/publications_e.html). 16 p.

Pooladi-Darvish, M., Hong, H., Theys, S., Stocker, R., Bachu, S., and Dashtgard S. 2008. CO<sub>2</sub> injection for Enhanced Gas Recovery and Geological Storage of CO<sub>2</sub> in the Long Coulee Glauconite F Pool, Alberta. SPE 115789 presented at the SPE annual Technical Conference and Exhibition, Denver, September 21-24, 2008.



Hassanzadeh, H., Pooladi-Darvish, M., and Keith, D.W. 2008. Accelerating CO<sub>2</sub> Dissolution in Saline Aquifers for Geological Storage – Mechanistic and Sensitivity Studies. Paper submitted (June 2008) to Journal of Petroleum Science and Engineering.

Michael, K., Bachu, S., Buschkuehle, B.E., Haug, K., and Talman, S. 2008. Comprehensive Characterization of a Potential Site for CO<sub>2</sub> Geological Storage in Central Alberta, Canada. In: Carbon Dioxide Sequestration in Geological Media – State of the Art. M. Grobe, J. Pashin, and R. Dodge, (eds.). AAPG Special Publication, In press.

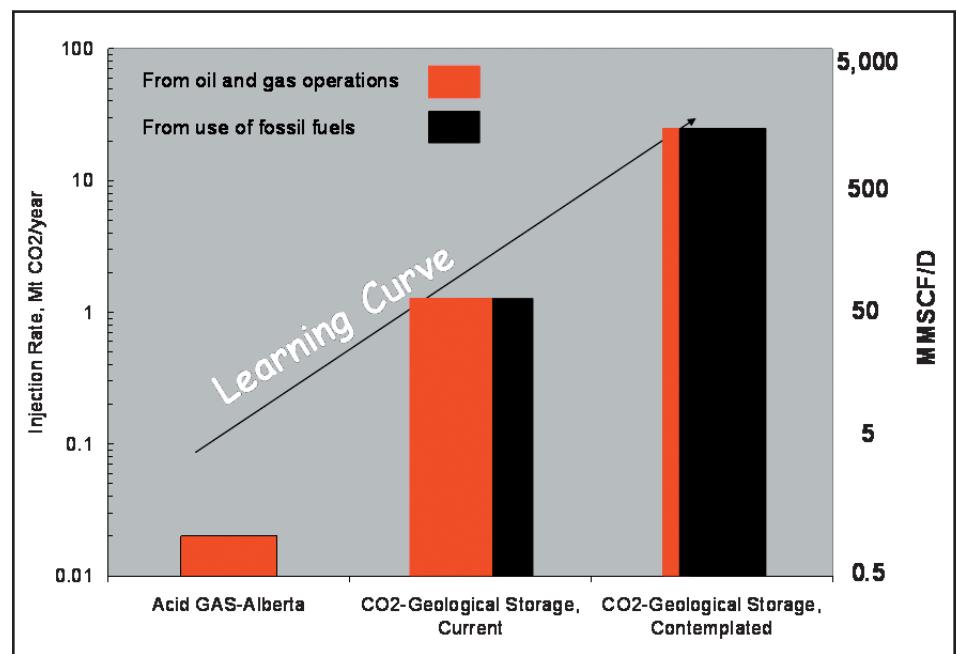


Figure 13.7. Current and projected CO<sub>2</sub> injection rates.

# Reservoir Engineering for Geologists

## Article 14 - Reservoir Simulation

by: Ray Mireault, P. Eng.; Nick Esho; and Lisa Dean, P. Geol.; Fekete Associates Inc.

In Fekete's experience, a well performed reservoir simulation represents the ultimate integration of geology, geophysics, petrophysics, production data, and reservoir engineering. Through simulation, the flow of multiple fluids in heterogeneous rock over time can be quantitatively estimated to gain insights into reservoir performance not available by any other means.

Initially, reservoir simulation was reserved for large reservoirs requiring large capital investments that justified costly, intensive studies such as offshore developments. However, simulation of more modest-sized reservoirs has increased as simulation software and computer capability have become more readily available. Oilfields under primary production, waterflood, and EOR typically qualify for reservoir simulation but its usage is not uncommon for gas fields, unconventional reservoirs, or pools undergoing CO<sub>2</sub> injection.

In broad terms, the geologist / geophysicist / petrophysicist's role in reservoir simulation is to reliably approximate the (a) stratigraphy, (b) structure, and (c) geometry of the reservoir flow unit(s) and the initial fluid distributions throughout. The aim of the exercise is to quantify and manage the subsurface knowledge and uncertainties. In the practical sense, a good model is the one that is fit-for-purpose utilizing sound geological reasoning and at the same time supports reservoir dynamics (e.g., fluid flow, history matching).

Geological data is often characterized by sparseness, high uncertainty, and uneven distribution, thus various methods of stochastic simulation of discrete and continuous variables are usually employed. The final product will be a combination of:

- observation of real data (deterministic component),
- education, training, and experience (geology, geophysics, and petrophysics), and
- formalized guessing (geostatistics).

The first step is the geologist's conceptual depositional model which (s)he must be able to sketch and explain to the other members of the team. The conceptual model should be broadly compared and tested with each discipline's observations and data (e.g., core

permeability versus well-test permeability, core porosity versus log-derived values) until the team has a consistent explanation of the reservoir's pre- through post-depositional history. Hydrocarbon reservoirs are too complex to develop a complete understanding "in one afternoon" so the process should be viewed as a series of ongoing discussions.

The next step is to define, test, and prioritize the uncertainties to be modeled and their impact on the overall dimensions of the model. For example, a gridblock height that is too large to reflect the layering in thin beds will introduce significant errors in the flow net-to-gross pay estimates as well as flow pathways. It is essential to agree upfront on the level of resolution and details to be captured in the model. The appropriate level of detail can be different for each reservoir and is also dependent on the purpose of the simulation, sometimes testing and iterations maybe necessary.

Next comes selecting the appropriate grid type (regular or faulted) to model the present day structure of the reservoir. Components to be modeled include the top of structure, faults, internal baffles to flow, and any areal variation in thickness and rock properties. The objective is to replicate the orientation, geometry, and effect of the structural imprint as it affects flow within the model. It is imperative to validate the fault-horizon network to ensure it is geologically feasible and to ascertain the absence of structural distortion and other problems.

Facies modeling is the next step in construction. Where available, the best practice is to integrate core data and outcrop analogues to constrain and refine log-derived facies type and property estimates. Understanding the facies distribution provides a tool for predicting reservoir quality away from the known datapoints. The geometry (length, width, thickness, and direction) of each facies body will affect the way heterogeneities in porosity and permeability are modeled. Attribute analysis (inversion/QI) and geobodies extracted from seismic data are also useful to further refine the geological model.

It is important to quality check at each step

of development to ensure consistency in the interpretation and reaffirm that the developing model is fit-for-purpose. A very detailed geological model may be unable to address the question(s) that the simulation team is attempting to answer.

The engineer's role in the process is to reliably simulate the performance of the geological model for the production scenario(s) under consideration by history matching a producing field and / or forecasting future performance. While it may seem that reservoir simulation would be straightforward if we only knew all the inputs, that perception is incorrect. Limited information unquestionably complicates the task but the most fundamental (and unavoidable) issue is the error introduced by approximating overwhelmingly complex physical geometries / interactions with simpler but manageable mathematical relationships.

Of necessity, simulation uses a sequence of three-dimensional gridblocks as a proxy for reservoir rock volume (see Figure 1). In order to keep the time, cost, and computing requirements of a simulation manageable, the total number of gridblocks is generally limited to less than 500,000, with a small simulation requiring less than 100,000 gridblocks. For either large or small projects,

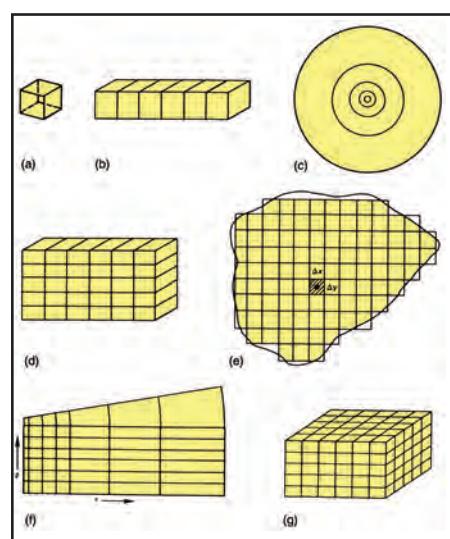


Figure 14.1. Typical reservoir simulation models (a) tank, (b) 1D, (c) 1D radial, (d) cross-sectional, (e) areal, (f) radial cross-sectional, and (g) 3D; Mattax and Dalton, 1990.

Data To Describe Initial (Static) Condition	
Rock	
Symbol	Definition
$D$	Formation top (structure)
$h_t$	Gross formation thickness
$h_n$	Net pay thickness
$\phi$	Porosity at initial pressure
$P_{cwo}^*$ vs. $S_w$	Drainage (water/oil) capillary-pressure function
$P_{cgo}^*$ vs. $S_g$	Drainage (gas/oil) capillary-pressure function
Fluid	
$B_o$	Oil FVF
$B_w$	Water FVF
$B_g$	Gas FVF
$\rho_o$	Oil density at standard conditions
$\rho_w$	Water density at standard conditions
$\rho_g$	Gas density at standard conditions
Additional Data To Describe Gas/Oil Displacement ( $S_g$ Always Increasing)	
Rock	
$k$	Specific (absolute) permeability
$k_{rg}$ and $k_{ro}$ vs. $S_o$	Gas and oil relative-permeability functions (drainage)
$c_f$	Rock compressibility
Fluid	
$R_s$ vs. $p$	Gas in solution vs. pressure
$B_o$ vs. $p$	Oil FVF vs. pressure
$B_g$ vs. $p$	Gas FVF vs. pressure
$\mu_o$ vs. $p$	Oil viscosity vs. pressure
$\mu_g$ vs. $p$	Gas viscosity vs. pressure
$c_o$	Oil compressibility
$c_w$	Water compressibility
Additional Data To Describe Water/Oil Displacement ( $S_w$ Always Increasing)	
Rock	
$k_{rw}$ and $k_{ro}$ vs. $S_w$	Oil and water relative-permeability functions (imbibition)
$P_{cwo}$ vs. $S_w$	Imbibition (water/oil) capillary-pressure function
Fluid	
$B_w$ vs. $p$	Water FVF vs. pressure
$\mu_w$ vs. $p$	Water viscosity vs. pressure
Additional Data To Describe Oil Invading a Gas Cap ( $S_w$ = Interstitial) or an Aquifer ( $S_g = 0$ )	
Rock	
$k_{ro}$ and $k_{rg}$ vs. $S_o$	Oil and gas relative-permeability functions (oil imbibition with hysteresis)
$k_{ro}$ and $k_{rw}$ vs. $S_w$	Water and oil relative-permeability functions (water drainage with hysteresis)
$P_{cgo}$ vs. $S_g$	Imbibition (gas/oil) capillary-pressure function
Additional Data To Describe Three-Phase Flow	
Rock	
$k_{ro}$ , $k_{rg}$ , and $k_{rw}$ vs. $S_w$	Three-phase relative-permeability functions**

\* $P_{cwo}$  and  $P_{cgo}$  need to be known at some definitive depth in the reservoir.

\*\*These functions are seldom available by experimental measurement and are costly to obtain. Simultaneous flow of three phases usually occurs in only a small fraction of the reservoir, so Stone's two-phase approximation is ordinarily acceptable. Three-phase capillary-pressure relationships are usually calculated from two-phase gas/oil and water/oil relationships.

a gridblock may represent a "unit" rock volume of one or more acres in areal extent and several feet thick (Figure 14.2).

While fluid saturations and / or other properties can vary significantly over an acre and / or several feet of reservoir (e.g., an oil-water transition zone), each gridblock has only a single value for each property (e.g., porosity, saturation of water, oil and gas, permeability, capillary pressure) of the gridblock. When the true variation in the reservoir is too great to be comfortably represented by a single average value, the solution may be to (iteratively) increase the density of the gridblocks ("fine grid") in a specific area of the reservoir. Alternatively, a separate, smaller simulation may be run and the results provided as input to the larger study, as when modeling fluid and pressure behaviour at the wellbore sandface.

Similarly, simulation must approximate the continuous movement of fluids and the resulting changes in fluid saturations with calculations performed at discrete timesteps. Though it does not occur in the real world, there can be abrupt changes in a gridblock's fluid saturation(s) as fluids move into or out of the gridblock. The usual solution is to limit the magnitude of the change to tolerable levels through (iterative) selection of smaller timesteps.

The use of discrete timesteps and discrete gridblocks with a single value for each property also leads to the dilemma of what values to use in modeling the fluid properties for flow between adjacent gridblocks and adjacent timesteps. This artifact of numerical simulation also has consequences on calculated performance that do not exist in reality. For further discussion, see Chapter 2 of the SPE Monograph Volume 13. Though there is no completely satisfactory answer to the problem, workable approximations for flow across gridblock boundaries and between subsequent timesteps exist. The choice of which to use in a particular situation often comes down to experience and iteration.

Figure 14.3. Rock and fluid properties (Mattax and Dalton, 1990).

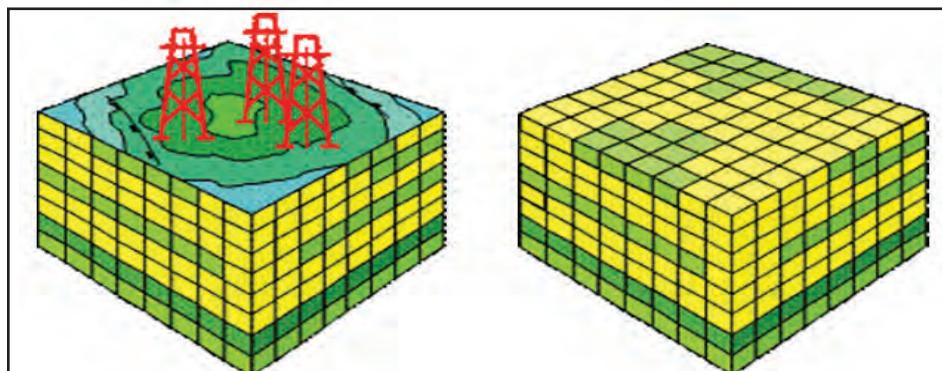


Figure 14.2. Example of 3D gridblocks.

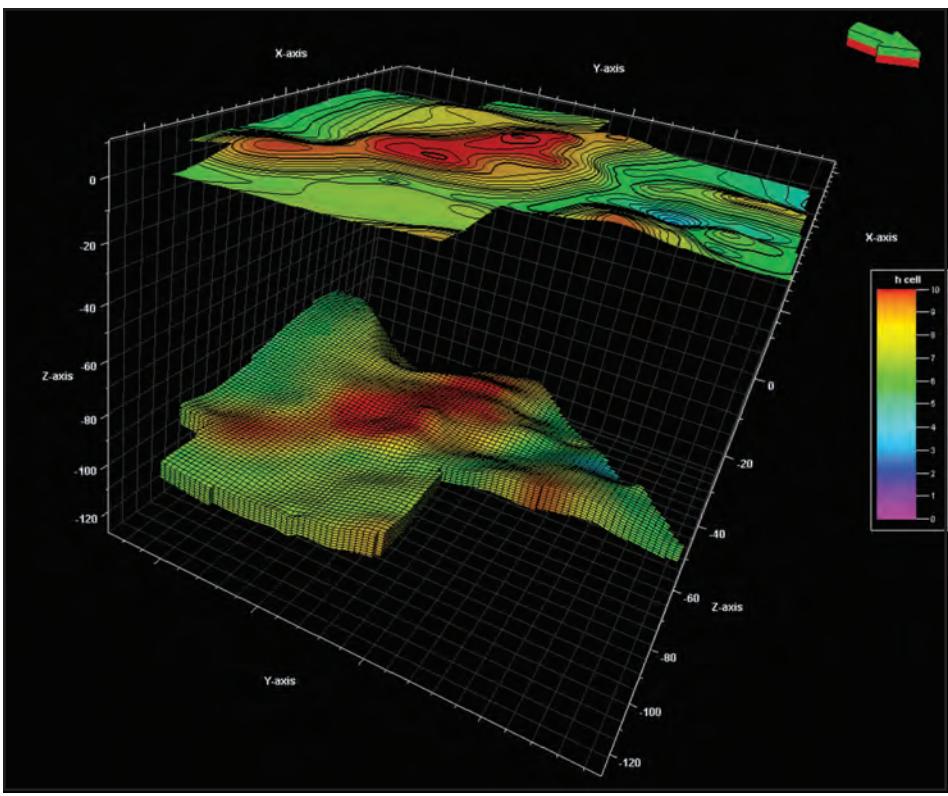


Figure 14.4. Visualization of 3D model.

#### DATA REQUIREMENTS

The rock and fluid properties required for reservoir simulation are summarized in Figure 14.3. Collecting the data and putting it into a form that can be imported in a reservoir simulator can be a major effort in itself.

#### ASSIGNMENT OF GRIDBLOCK PROPERTIES

Chapter 4 and 5 of SPE Monograph 13 provide further discussion on the challenges of assigning representative average values for rock and fluid properties to each gridblock in a simulation model and the size of gridblocks and timesteps to use. The choices are interrelated and influenced by:

- the areal and vertical variation in the observed rock and fluid properties,
- the type of physical processes being modeled, and
- the solution techniques being used.

Often, the best approach is to select the smallest gridblock size and number of layers needed to accurately describe the changes in reservoir facies, reservoir geometry, and fluid distribution. For example, fluid saturation changes in an oil-water transition zone might require gridblocks with an unusually small height of one foot or less to adequately represent the change in saturation through the transition zone with the series of single values available to “stacked” gridblocks. Production and injection wells

and internal no-flow boundaries such as shale deposits or non-conducting faults are other features that can be the determining factor in selecting gridblock size.

Porosity and permeability distribution are nearly always important and are often the keys to reservoir performance. Sensitivity studies generally indicate that if the facies distributions through the reservoir are correctly modeled and each facies is assigned the correct order of magnitude for permeability, the relatively small errors in the absolute value of permeability assigned to each gridblock are insignificant, since they are compensated for by the large area of flow that is available for fluid movement.

Constructing the entire reservoir model with a minimum size of gridblock captures the level of detail needed for critical aspect(s) of the reservoir simulation but over-compensates in non-critical areas. Subsequent inspection of the model, keeping in mind the physical processes (i.e., thermal processes) and solution techniques that will be used to model fluid flow, will identify areas of the reservoir that do not require the level of detail that was built into the original model. The process of subsequently selecting and reducing the number of gridblocks used to model the non-critical areas is referred to as “upscale.”

Selection of the appropriate timestep is generally left to last, because the pore

volume of a gridblock and rate of fluid flow (production) both influence the rate of change in a gridblock's fluid saturations over time. Limits on the rate of saturation change that are developed from experience, are generally used to determine the largest timestep size that will present apparently smooth results when mapped or graphed. This process is done internally by the simulator to ensure smoothness of results.

#### SIMULATION OUTPUT

Since it is not possible to individually inspect the millions of calculations that are performed in a simulation, editing and graphical presentation of the output is crucial to assessing the consistency and reliability of the results. As a minimum, the output graphs should include:

- oil, water and gas production rates;
- producing gas-oil ratio;
- producing water cut or water oil ratio, and
- bottomhole flowing pressures.

Maps / movies of fluid saturation and reservoir pressure trends are also invaluable to assessing the quality and consistency of the output. For example, inconsistent pressure behaviour – related to negative cell volumes – may indicate that there is an issue with the gridding and / or assigned transmissibility of gridblocks along a fault zone.

#### USES AND LIMITATIONS OF SIMULATION

As computing power and software capability have developed, the “art” of reservoir simulation has proven to be a valuable complement to other methods of reservoir analysis. To the geologist, a threedimensional model is the ultimate tool for visualizing and then communicating the reservoir interpretation to others (Figure 14.4). As a working tool, it integrates the partial interpretations provided by each discipline and allows for an unsurpassed level of consistency checks.

To the reservoir engineer, modern-day reservoir simulation software provides the capability to visualize and present the movement of fluids through rock in accordance with physical principals. With it we can:

- comparatively assess the hydrocarbon recovery efficiency of various production systems that could be considered for a given reservoir prior to their implementation and
- more closely monitor producing reservoir trends and more quickly

identify the probable causes of deviations from forecasted performance, particularly during the early life of a reservoir.

Prior to production, Monte Carlo volumetric estimates are still the best tool to quantify the uncertainty in the gas or oil-in-place within a deposit. But reservoir simulation allows comparison of production performance over the probable volumetric range at a level not previously available. Simulation sensitivity studies are invaluable in identifying the uncertainties that can have a significant impact on production / financial performance and in focusing efforts to acquire additional information and / or modify development plans to mitigate potential impacts.

For a producing reservoir, material balance still provides the most accurate estimates of oil- and / or gas-in-place. Accordingly, tuning the in-place volumes in the simulator to the material balance results improves the diagnoses of well performance and allows for better reservoir management.

#### **REFERENCES**

Mattax, C.C. and Dalton R.L. 1990. *Reservoir Simulation*. Society of Petroleum Engineers, Henry L. Doherty Series, Monograph Vol. 13.

