RESERVOIR ENGINEERING FOR GEOLOGISTS

Part 5A – 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 1 presents the different P/Z curve trends that result from different drive mechanisms.

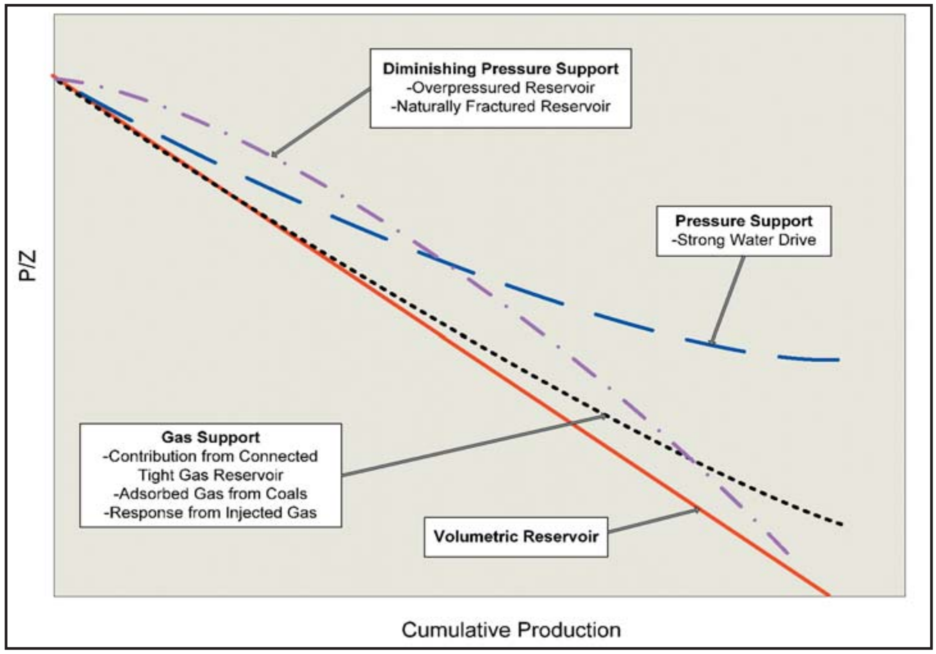

Figure 1. Gas reservoir P/Z material balance diagnostics.

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 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 1, 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 (Bo) and solution gas ratio (Rs) 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 to 1.5x10^{-6} kPa^{-1}
  - Gas: 10^{-3} to 10^{-5} kPa^{-1} (Varies significantly with reservoir pressure.)
  - Water: 0.2 to 0.6x10^{-6} kPa^{-1}
  - Oil: 0.4 to 3x10^{-6} kPa^{-1}

Thus rock compressibility can be ignored in normally pressured or volumetric gas reservoirs (see Figure 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 hydrocarbons (see Figure 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

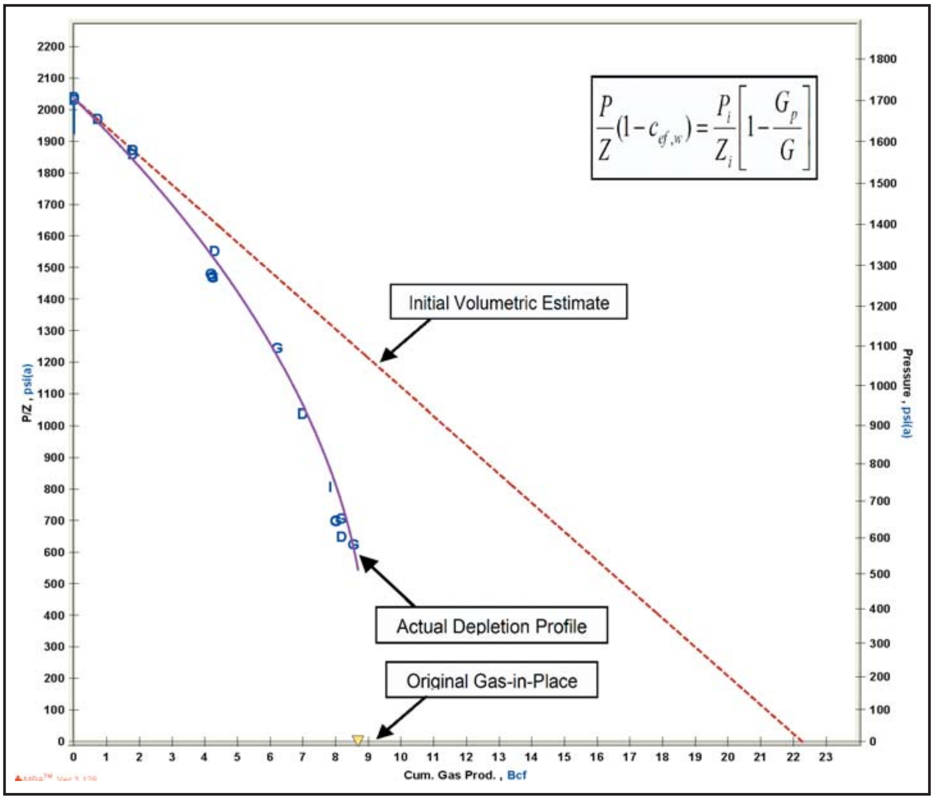

Figure 2. Multi-well gas reservoir P/Z plot.

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 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 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

(Continued on page 26...)

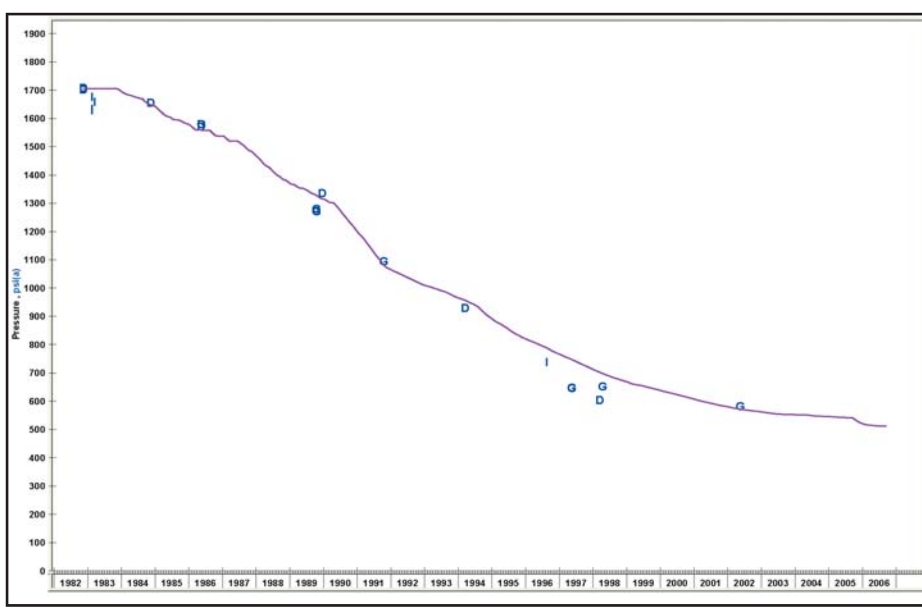

Figure 3. Multi-well gas reservoir pressure vs. time plot.

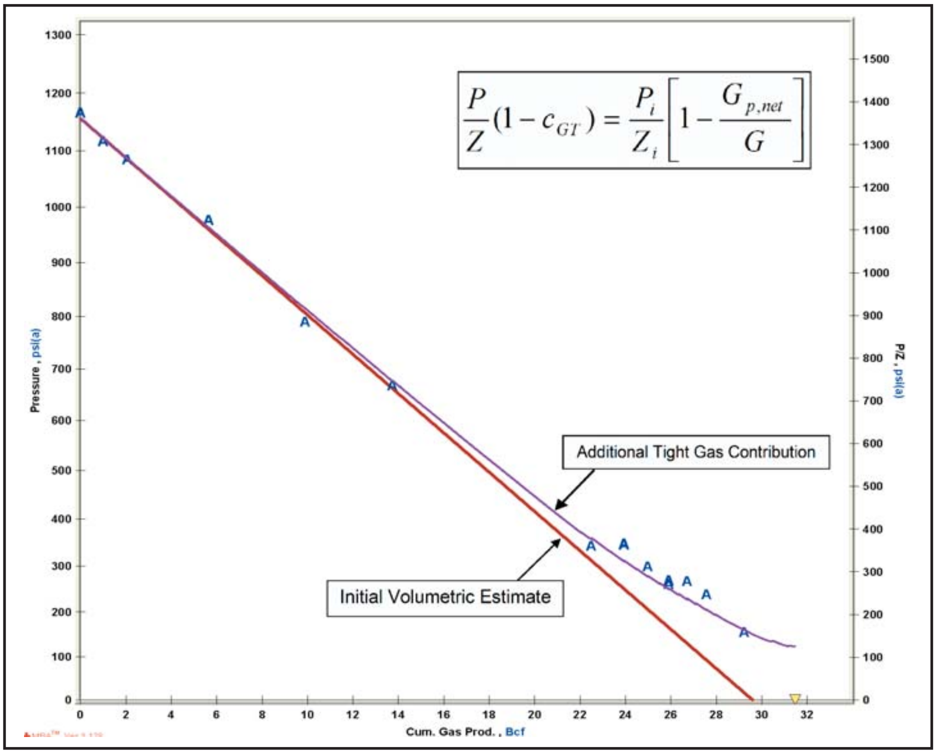

Figure 4. Single well gas reservoir P/Z plot.

(...Continued from page 25)

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 2, Figure 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 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 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:

$$\frac{P}{Z} = \frac{P_i}{Z_i} - Q * \frac{(P_i)}{G_i * Z_i}$$

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_i = the original gas-in-place

As the equation and Figures 1 and 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 1000 mD) permeability reservoirs. A strong upward curvature that develops into a horizontal line, as presented in Figure 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 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 1 and the single well reservoir of Figure 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.

Our next article, in the March issue of the Reservoir, will continue the Material Balance (Part 5B) discussion for Oil Reservoirs.

This article was contributed by Fekete Associates, Inc. For more information, contact Lisa Dean at Fekete Associates, Inc.

Fekete