Estimating reservoir oil volume and its likelihood from 3C-3D seismic data, well logs, and geostatistics

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Summary

Defining the volume of hydrocarbons in a reservoir is a key aspect of resource estimation. Determining the likelihood of this volume is critical for reserve evaluation. We outline a geophysical framework using 3C-3D seismic data, well logs, and geostatistics to assist in this assessment. This proposed procedure is applied to the Blackfoot oilfield, Alberta. The predicted original oil in place and its likelihood (a P90 of 4.5MMbbl computed from 1995 data) compares reasonably well with that inferred from actual cumulative production up to 2011 (5.5MMbbl).

Introduction

The volume of hydrocarbon reserves is a primary component of an energy company's value. Estimating that volume is a complicated, but essential and regulated, part of the resource industry's business. Geophysical methods continue to advance and are playing a more fundamental role in reservoir assessment (Hardage, 2009; PRMS-AD, 2011). Recently, seismic imaging was qualified as a reliable technology (Sidle and Lee, 2011), providing input to a further discussion on the related SEC requirements for Seismic Technologies.

Estimating the reservoir's volume

This paper presents a framework to estimate the likelihood of a reservoir pore (oil) volume using multicomponent (3C-3D) seismic data, well logs, and geostatistics. The multicomponent (3C-3D) seismic data and well log measurements are first interpreted and combined to estimate rock properties using three methodologies: inversion, geostatistics, and multi-attribute analysis (Todorov and Stewart, 1997; Todorov et al., 1998). The 3C-3D seismic data set and well logs are from the Blackfoot oilfield, Alberta. Conventional model-based inversion is applied to the P-P data to estimate the acoustic impedance. A 3-D converted-wave (P-to-S on reflection) inversion for shear velocity computes a PS weighted-stack followed by a conventional inversion algorithm. Geostatistical methods of kriging, cokriging, and stochastic simulation are used to derive a sand-shale distribution as well as a time-to-depth conversion from the various seismic and well log data. Linear multi-regression and neural networks next derive a relationship between porosity logs and a set of seismic attributes. We find that PS attributes are some of the most important. The sand thickness (gross) around the reservoir, sand percentage (for net sand thickness), and porosity are then used to generate a pore volume. We estimate an average oil saturation from the well logs, then compute an oil column height (OCH = gross isopach · sand percentage · porosity · oil saturation; Figure 1). Multiplying the OCH by the reservoir area provides a total hydrocarbon pore volume. This is the beginning of the volumetric calculation for the reservoir.

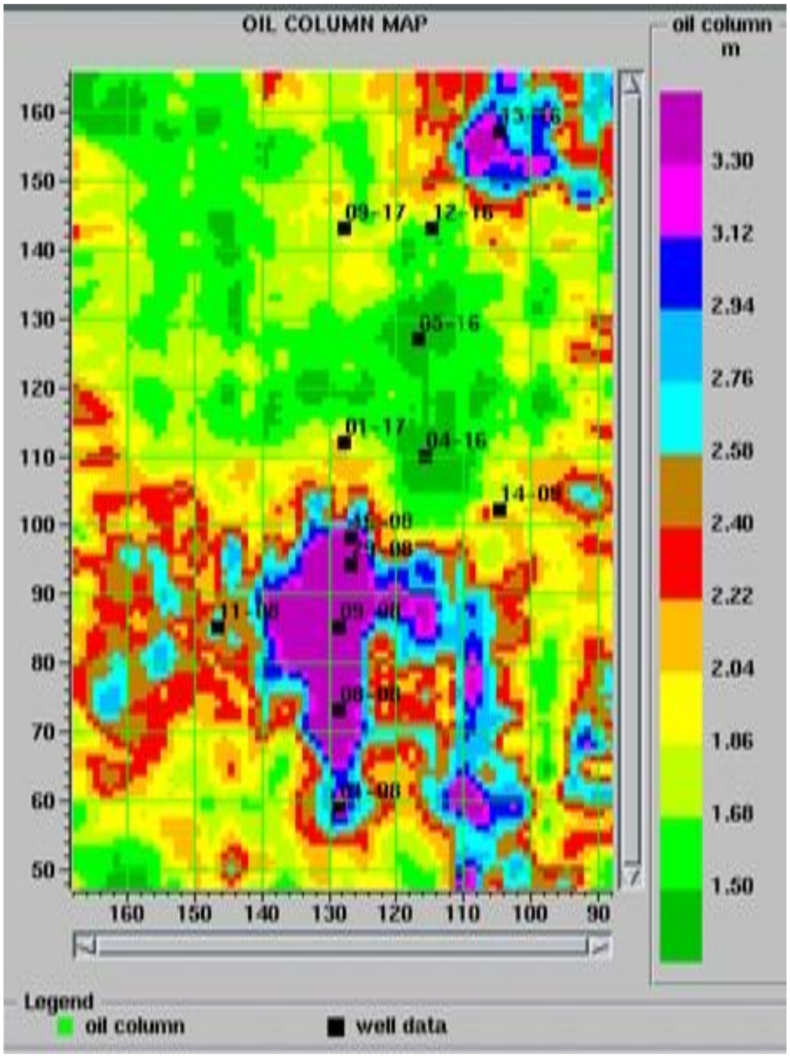

Fig 1. Oil column map for the Blackfoot oilfield, Alberta.

We need to now attempt to assess the quality of this volumetric assessment (Uffen, 2011). Our approach is to gather all of the errors (or range of validities) of each part of the total pore volume equation. Blind tests (validations) are used with geostatistics to estimate errors in the predicted thickness and percentage of sand. The errors in the neural net values for porosity are also estimated by comparing predicted logs with actual ones. We sum all of these fractional errors to produce a range of validities for the total hydrocarbon pore volume, using a Taylor expansion approach which is presented below:

$$\left(\frac{\sigma_{HCPV}}{HCPV}\right)^2 = \left(\frac{\sigma_{thickness}}{thickness}\right)^2 + \left(\frac{\sigma_{\%sand}}{\%sand}\right)^2 + \left(\frac{\sigma_{\phi}}{\phi}\right)^2 + \left(\frac{\sigma_{S_{HC}}}{S_{HC}}\right)^2 + \left(\frac{\sigma_{Area}}{Area}\right)^2$$

where HCPV is the hydrocarbon pore volume, % sand is the percentage of sand, ϕ is the porosity, and S_{HC} is the oil saturation. The values in the denominators in the equation above are the average values for each property in the Blackfoot reservoir, so that each term presented is the coefficient of variation specific for each parameter (Deutsch, 2002).

This error or validity range in the pore volume can be attached to a cumulative probability. Various points in the cumulative probability are interpreted as likelihoods of the volumes indicated (Figure 2).

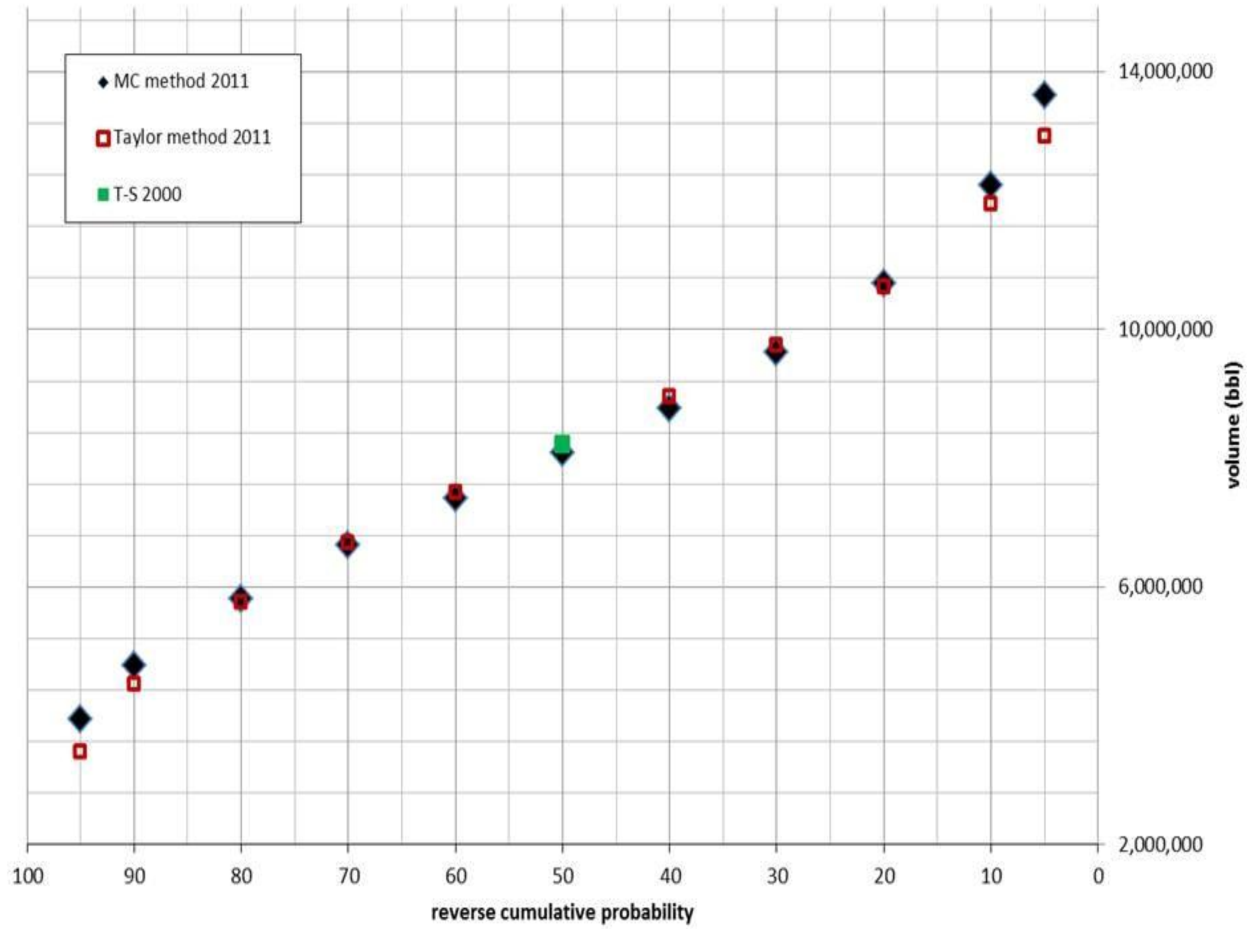

Fig 2. Reverse CDF for the predicted hydrocarbon pore volumes at the Blackfoot oilfield, Alberta.

We also use these validity ranges in a Monte Carlo approach to predict oil volume likelihoods (Figure 3). The results obtained using these two approaches suggest hydrocarbon volumes for the Blackfoot pool: with a ten-percent probability (P10) of 12.5 MMbbl (there is 10% of chance that this reservoir has more than 12.5 MMbbl), P50 of 8MMbbl, and a P90 of 4.5MMbbl. A recent accounting (Ken Mitchell, pers. comm., 2011), using the actual amount of oil produced from the Blackfoot pool, suggests an original oil in place of 5.5MMbbl.

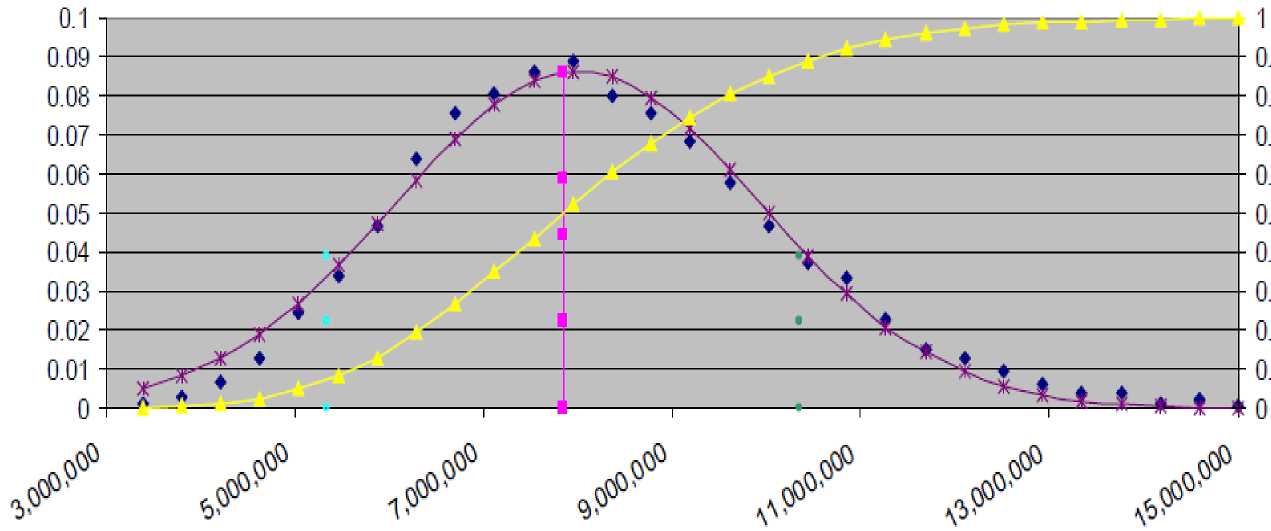

Fig. 3. The probability curves for oil volumes at the Blackfoot oilfield, Alberta.

Conclusions

We have outlined a procedure to estimate hydrocarbon volumes in a reservoir. The estimation method uses 3C-3D seismic data and well logs, then combines them using geostatistics. From these data and their errors, we determine the likelihood of associated reservoir volumes. This procedure has been applied to the Blackfoot oilfield, Alberta. The reservoir volumes estimated from the original 1995 data and its current cumulative production are in reasonable agreement.

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