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Probabilistic Reserves Assessment Using A Filtered Monte Carlo Method In A Fractured Limestone Reservoir

L.R. Stoltz SPE, Fletcher Challenge Energy Taranaki, M.S. Jones SPE, Fletcher Challenge Energy Canada, A.W. Wadsley, Optimiser Consulting

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Abstract

A new approach to the estimation of reserves in a fractured limestone reservoir is presented and verified with a lookback analysis over the past five years of production from the field. This approach uses a filtered Monte Carlo method to integrate independent reserves calculations based upon volumetric, material balance, well pressure survey analysis, and well decline estimates of oil in place and recovery. For the Waihapa-Ngaere field, two estimates of oil in place are available: a volumetric estimate obtained from mapped gross reservoir volume and formation parameters; and a material balance estimate obtained from pressure decline and production data. Independent estimates of oil recovery can be obtained from estimation of recovery factors based upon areal and vertical sweep in the fractured reservoir, and recovery obtained from extrapolation of well decline. The approach taken, that is to integrate all of the available information and only accept parameter sets which are consistent, led to an estimate of reserves and production potential from the field which has proved remarkably accurate as a predictor of field performance and recovery over the past five years.

Background

The Waihapa Field lies at the southern end of the Tarata Thrust zone, within the eastern edge of the Taranaki Basin, New Zealand (Figure 1). The field was discovered in February 1988 with flows of up to 3124 bopd and gas up to 3.2 MMscf/d from the fractured Tikorangi Limestone during drillstem testing of the Waihapa-1B well. The Toko-1 well, to the north of the Ngaere area of the field, was the first well to be drilled in the area in November 1978 but a test of the top section of the Tikorangi formation was inconclusive. Following the success of the Waihapa-1B well, Waihapa-2, 4, 5, 6, 6A were drilled in the structure from the period 1988-1989 with all but Waihapa-6 (which was tight) being successful. Northern extension wells Ngaere-1, -2 and –3 were successfully drilled from March 1993 through February 1994.

Geological Setting. The Waihapa structure is the southern termination of a west-directed thrust sheet which formed as a result of movement along the NS-trending Taranaki Fault. At top Tikorangi level the structure develops from a simple low-amplitude, symmetrical fold in the south to an overthrust structure in the north. A major tear fault, with a westerly displacement of approximately 2 km, lies between the Ngaere-2 and Ngaere-3 wells. A schematic top depth map showing well locations and the major faults, as seen on seismic, is shown in Figure 2.

The Tikorangi Formation is an interbedded foraminiferal limestone, siltstone and mudstone sequence averaging 230m thickness in the Waihapa area. Diagenetic features in the limestone matrix include extensive pressure solution and concomitant calcite cementation reducing the original primary porosity to the typically observed 5 to 7%. The matrix, although of reasonable measured porosity, is of low permeability (< 0.01 mD), is water saturated and is currently postulated to make no contribution either to oil production or to pressure support to the field. The significant secondary porosity development for the oil accumulation is from post-burial fracturing of the formation. Fracturing is common over the entire thickness of the Tikorangi Formation and extensive over a wide area.

Based on a field wide correlation, four units have been defined within the Tikorangi Formation. Unit A, the uppermost, appears as a relatively uniform interval with a blocky GR and sonic response, both indicating massive moderately clean carbonate. Unit B has a more irregular log response, indicative of an interbedded lithology, most likely limestone and shale. Unit C, directly beneath this, has a blocky appearance indicating relatively clean carbonate. This generally grades to a more shaly lithology towards the top of unit D. The lowermost unit, unit D, has a more uniform character and appears as a more silty/shaly lithology.

Introduction

No reservoir parameter in the Waihapa field is known with any confidence: fracture porosity and areal distribution is not known; fracture compressibility can not be measured directly; the reservoir closure has not been mapped or the nature of the closure identified; the initial oil-water contact was not penetrated; and the reservoir top structure is uncertain outside of well control because of large uncertainty in seismic velocity trends in the field. Thus it is extremely difficult to obtain reliable estimates of oil initially in place (OIIP) and reserves for the field. However, a large body of data has been gathered over time, including well and average reservoir pressures, oil and water production trends, interference and transient pressure analyses, core analyses, interpretation of 3-D seismic, and results of specialist studies. Much of this data appeared only marginally consistent. For example, the CO_2 concentration for the produced gas was 7% in the Waihapa-1B well and 12% in the Waihapa-2 well implying different oil compositions and possible reservoir compartmentalisation. Notwithstanding this, these are the closest wells in the field (600m apart) and are in pressure communication (as unequivocally shown by interference test analysis).

The approach taken was to integrate all of the quantitative data observations into a single Monte Carlo estimation procedure for oil in place and reserves. For the field, two independent estimates of oil in place are available: a volumetric estimate obtained from mapped gross reservoir volume and formation parameters; and a material balance estimate obtained from pressure decline and production data. Independent estimates of oil recovery can be obtained from recovery factors based upon areal and vertical sweep in the fractured reservoir and, and recovery obtained from extrapolation of well decline. Each reservoir parameter is estimated independently and only those sets of parameters which lead to consistent estimates of OIIP and recovery are accepted. This methodology filters out the inconsistent sets of reservoir parameters and is referred to in this paper as the filtered Monte Carlo method.

In 1989, just after the start of field production, it was uncertain as to the nature of the fractured reservoir and whether or not the matrix was contributing to flow. At this time the filtered Monte Carlo method was used to differentiate between alternative reservoir models. Following further drilling and production a revised analysis was undertaken in 1993 which has proven to be a robust estimator of reserves to the present time.

Fractured Reservoir Models

After Nelson[1] we can distinguish four types of fractured reservoir model: Type 1, fractures provide the essential (hydrocarbon) reservoir porosity and permeability; Type 2, fractures provide the essential reservoir permeability; Type 3, fractures assist permeability in an already producible reservoir; Type 4, fractures provide no additional porosity or permeability but create significant reservoir anisotropy.

Classification of the Waihapa Tikorangi Formation. The Tikorangi formation is a Type 1 reservoir under this classification. That is, the fracture network provides the whole of the hydrocarbon storage. This interpretation is based upon core observations and wire-line log interpretation: very low matrix permeabilities were measured in core plugs (<0.01mD); oil was not observed in solvent extracted core plugs; and hydrocarbon saturations were not interpreted in logs.

Matrix Fracture Communication. Identification of the degree of matrix fracture communication in the reservoir is important notwithstanding that the potential for oil storage in the matrix is small. Even at the low permeabilities measured in the Tikorangi core plugs, there is potential for water movement from the matrix into the fractures because of the large surface area available to flow. At permeabilities of <0.001mD water influx from the matrix can still make a substantial contribution to material balance and pressure support.

Both cemented and slickenside fractures have been observed in Waihapa cores. Calcite cementation provides an impermeable barrier between the fracture channels and matrix porosity, whilst slickensiding gives rise to a zone of compacted and crushed grains along the fracture planes which can significantly reduce permeability and hence matrix-fracture communication. It is consistent with these observations to propose that the Waihapa Tikorangi formation is a *non-porous* fractured reservoir with no fracture-matrix interaction.

In 1989, when the first filtered estimates of OIIP were made for the Waihapa Field, pressure surveys were interpreted as classic dual porosity systems. Thus, at that time, the *porous* fractured reservoir model was considered more likely in which the matrix can provide pressure support (albeit water only) to the fractures. Subsequently, in November 1990, reanalysis of the transient pressure test trends showed that a conventional, single porosity model (fluid storage and permeability assigned solely to the fracture system) with boundary gave better agreement between observed and calculated pressure trends than did the dual porosity model. Notwithstanding this the analysis presented below also includes a term for fracture-matrix interaction.

Dual Fracture Model. The dual fracture model consists of a primary fracture network of large open fractures in communication with a secondary fracture system of smaller, less extensive micro-fractures or fissures. Large extensional fractures have been observed with fracture widths up to 16mm that could constitute the primary fracture system. There are numerous conjugate shear fractures on a smaller scale. Shear fractures (and their conjugates) may exist on all scales, from fractured grains in the matrix to reservoir wide fractures across the whole formation. These fractures may be fold related[2], and can be associated with faulting. The relationship of fractures to faults exists on all scales: Friedman[3] used the orientation of microscopic fractures from oriented cores in the Saticoy Field to determine the orientation and dip of a nearby fault. In a Triassic limestone, a frequency analysis[4] of widths of open fractures was interpreted to arise from several sets of fracture distributions superimposed upon each other: the first was due to initial tectonic stresses; the second to weathering and exfoliation, and other sets to karstic and strongly faulted zones.

In the Waihapa Tikorangi no evidence exists for sub-aerial exposure (that is, weathering) and detailed core analysis failed to find evidence of micro-fractures or fissures. However, there is evidence of different fracture regimes in the field which could possibly lead to a dual fracture flow regime. There is a dominant NE to ENE striking trend with an apparent but less dominant N to NW striking trend. The NE-ENE striking sets are generally near vertical and the N-NW sets have shallow to moderate dips (20 to 50^{o}). Many fractures seen in Waihapa-2 and Ngaere-2 are highly shattered with pieces of host rock being incorporated in the mineralising calcite. In the Ngaere-2 well these are northerly striking which is consistent with the trend of reverse faulting observed in the seismic interpretation.

Complex Porosity Model. The complex reservoir model is similar to the dual fracture model with the additional assumption that both fracture sets are in communication with a porous and permeable matrix.

Dual Porosity Model. The dual porosity reservoir model assumes that there is a single dominant fracture system in communication with a porous and permeable matrix.

Non-Porous Fracture Model. The non-porous fracture model, or single porosity fracture model, is equivalent to a conventional single porosity model in which the fracture system provides all of the reservoir storage and permeability.

Fracture Continuity and Permeability. Calculations[5] of effective fracture permeability for a 10mm opening based upon (laminar) Poiseiulle flow between the fracture walls gave values ranging from 1000mD for 80m spacing between fractures to greater than 80000mD for a fracture spacing of 1m. These calculated permeabilities are significantly higher than the permeability interpreted from pressure test analyses of between 27mD and 158mD. The most likely explanation for this discrepancy between observed permeability and theoretical calculation is that the large extensional fractures observed in core are not continuous or connected over large distances. They may be *en echelon* with fluid flow from fracture to fracture being through lower permeability matrix or, more likely, through a network of smaller fissures. Alternatively, the degree of cementation in these fractures may vary, with some sections being almost completed cemented with paths for flow being either extremely tortuous or disconnected.

Components of Material Balance and Volumetrics

The reservoir model used for the material balance calculations is based upon a Type 1, complex porosity, fractured reservoir with gas cap and aquifer, no hydrocarbon saturation in the matrix, and constant bubble-point pressure in the oil column,

The reservoir is naturally zoned into gas, oil and water zones with boundaries at the initial gas-oil and water-oil contacts, respectively. Subzones also develop during production of the reservoir: in particular, a *gassing zone*[6] develops below the original gas-oil contact (OGOC) as the reservoir pressure drops. Initially, the pressure at the original gas-oil contact equals the bubble-point pressure, with an increase in pressure with depth due to the oil density gradient down to the original oil-water contact (OOWC). As the average pressure in the reservoir declines, both the gas-cap and the water-leg will expand (the latter due also to aquifer influx) to new contact levels, being the current gas-oil contact (GOC) and the current oil-water contact (OWC). Because there are assumed to be no capillary forces present in the fracture networks, there will be no water-transition zone above the OWC and no residual oil saturation in the gas-invaded and water-invaded zones behind the new contacts. However, there could be oil saturations trapped in dead-end fractures.

As the reservoir pressure declines, the pressure at the GOC will not equal the initial bubble-point pressure of the oil, but will be in equilibrium with oil at a lower bubble-point. Because the oil column was everywhere at the same initial bubble-point (see PVT discussion below), we can define a current bubble-point level (BPL) as that depth where the oil pressure equals the initial bubble-point pressure. The zone between the current bubble-point level and the current gas-oil contact is called the *gassing zone*. In this zone, the oil pressure is everywhere below the initial bubble-point pressure and gas is being liberated from solution. This gas percolates vertically upwards to form either secondary gas caps or merge with the expanded original gas cap of the reservoir.

The following zones can be identified: original gas-cap, gas invaded zone, gassing zone (saturated oil), under-saturated oil column, water-invaded zone, and original water-leg.

Volume Contributions to Reservoir Voidage. Oil production for a depleting reservoir is a result of volume changes for all of the communicating components of the reservoir system:

Shrinkage of total reservoir volume

primary fracture volume	$(1+m+w)c_f\varphi_f$
secondary fracture column	$(1+m+w)c_d\varphi_d$
matrix volume	$(1+m+w)c_m\varphi_m$

Expansion of water in matrix

$$(1+m)\varphi_m S_w c_w$$

Expansion of oil in undersaturated zone

$$(1-s)(\varphi_m(1-S_w)+\varphi_f+\varphi_d)c_o$$

Shrinkage of oil in gassing zone

$$s(\varphi_m(1-S_w)+\varphi_f+\varphi_d)(B_{ob}/B_{oi}-1)$$

Expansion of gas cap

$$m(\varphi_m(1-S_w)+\varphi_f+\varphi_d)(B_g/B_{gi}-1)$$

Liberation of gas from gassing zone

$$s(\varphi_m(1-S_w)+\varphi_f+\varphi_d)R_{sbp}(B_g/B_{gi})$$

Expansion of water-leg

$$w(\varphi_m+\varphi_f+\varphi_d)c_w$$

Expansion of aquifer

$$B_w W_e$$

Material Balance Estimate of Oil in Place. At the start of production the gassing zone has not formed, therefore s=0; and the aquifer has not been activated, therefore W_e=0. Thus the general material balance equation, at the start of production, is:

$$\begin{aligned}N_{mat} = (dN/dP)/(\{ & (1+m+w)(c_f\varphi_f+c_d\varphi_d+c_m\varphi_m)\\ & +(1+m)\varphi_m S_w c_w\\ & +(\varphi_m(1-S_w)+\varphi_f+\varphi_d)c_o\\ & +m(\varphi_m(1-S_w)+\varphi_f+\varphi_d)c_g\\ & +w(\varphi_m+\varphi_f+\varphi_d)c_w\}/\{\varphi_m(1-S_w)+\varphi_f+\varphi_d\})\end{aligned}$$

The decline rate, dN/dP, is defined as the cumulative production per unit pressure decline at the start of production. Thus it is unaffected by pressure support arising from creation of the gassing zone or from aquifer influx.

The components of material balance included in this complex porosity reservoir model are: shrinkage of total fracture volume, expansion of oil in primary fractures, expansion of oil in secondary fractures, expansion of water in matrix, expansion of water below oil-water contact, and expansion of gascap. The components of material balance excluded from the model are: shrinkage of oil in gassing zone (0 @ t=0), gas liberated in gassing zone (0 @ t=0), aquifer influx (0 @ t=0), expansion of oil in matrix (0 in this model, S_w=1), expansion of gas in matrix (0 in this model).

Volumetric Estimate of Oil in Place. Initial oil in place can be related to gross rock volume of the oil column by the equation:

$$N_{vol} = f_{open}f_{map}(\varphi_m(1-S_w)+\varphi_f+\varphi_d)(V(z_{owc})-V(z_{goc}))/B_{oi}$$

Calculation of Oil in Place and Reserves

Two estimates of oil in place are calculated during the Monte Carlo simulation. These are the volumetric estimate, N_{vol}, obtained from the mapped gross reservoir volume and formation parameters, and the material balance estimate, N_{mat}. In order to obtain a consistent estimate of oil in place, both the volumetric and material balance estimates were rejected if they were not sufficiently close:

N_{vol} and N_{mat} rejected if $|1-N_{mat}/N_{vol}| > \varepsilon$

where ε is fractional tolerance, set to 0.1 in this analysis.

Recovery. Recovery can be estimated from a volumetric sweep efficiency and oil remaining in the reservoir between the abandonment gas-oil contact, z_{agoc}, and the abandonment oil-water contact, z_{aowc}. Total remaining oil in the reservoir at abandonment is

$$\begin{aligned}N_a = f_{open}f_{map}\{ & (\varphi_m(1-S_w)+\varphi_f+\varphi_d)(V(z_{aowc})-V(z_{agoc}))\\ & + (1-E_aE_v)(V(z_{agoc})-V(z_{ogoc}) + V(z_{oowc})-V(z_{aowc}))\}/B_{oa}\end{aligned}$$

Volumetric recovery is defined by $R_{vol} = 1-N_a/N_{vol}$.

A further constraint is applied to the recovery obtained from the oil in place estimate by application of the recovery efficiency. The volumetric recovery is rejected if it is not sufficiently close to the recovery estimate, R_{well}, obtained from well decline curve analysis:

R_{vol} and R_{well} rejected if $|1-R_{well}/R_{vol}| > \varepsilon$.

This criterion also ensures that the volumetric estimate is realistic and can be tied to a proper well development sequence. In particular, extremely low or high estimates will be rejected if they cannot be realised by at least one well sequence.

Storativity. Consistency can also be realised with respect to well-test analysis in the case of dual porosity or dual fracture reservoir models. The ratio of primary fracture storativity to volumetric system storativity, ω_{vol}, is defined by:

$$\omega_{vol} = s_f / s_{tot}$$

where

$$s_f = \varphi_f(c_f+c_o),$$
$$s_{tot} = \varphi_f(c_f+c_o)+\varphi_d(c_d+c_o)+\varphi_m(c_m+S_w c_w+(1-S_w)c_o).$$

The Monte Carlo trial is rejected if the volumetric storativity ratio is not consistent with the storativity ratio, ω_{pre}, calculated from pressure test analysis:

ω_{vol} and ω_{pre} rejected if $|1-\omega_{vol}/\omega_{pre}| > \varepsilon$.

Based on the analysis of interference tests, an independent constraint can be also imposed on primary fracture storativity calculated volumetrically, s_f, and from interference test analysis, s_{pre}:

s_f and s_{pre} rejected if $|1-s_f/s_{pre}| > \varepsilon$.

Further, fracture storativity is the product of fracture compressibility and porosity. Thus a further constraint can be applied to the independently sampled storativity, compressibility and porosity values:

φ_f, c_f and s_f rejected if $|1-\varphi_f c_f/s_f| > \varepsilon$.

Reservoir Parameters

No reservoir parameter is known with any confidence in the Waihapa Field. The following discussion highlights the difficulties encountered in defining or measuring these values and, by implication, explains the necessity of using the filtered Monte Carlo method for reserves estimation.

Areal Closure. Neither the areal extent of fractures nor the nature of the reservoir closure to the north of the field is known with any confidence. A separate pressure regime is known to exist to the north and updip of the Toko-1 and Toko-2 wells. The Waihapa reservoir closure could be due to faulting or lack of fracturing but no feature has been observed which clearly defines the reservoir extent. In the analysis, separate depth volume tables were derived for both the Waihapa/Ngaere area to the Ngaere-3 well, V_{WN} ,and for the undeveloped Toko area to the north of the field, V_{TK}. A combined depth volume table for the whole field was defined by

$$V(z) = V_{WN}(z)+\theta_V V_{TK}(z)$$

where $\theta_V \subset U(0,1)$ was a parameter selected from a uniform distribution between 0 and 1.

Mapping Uncertainty. Because of the significant velocity gradients in the field, depth conversion of seismic time maps outside of well control is uncertain but is likely to be systematically in error in the flanks of the field. This uncertainty was expressed by multiplying the total depth volume relation for the field by a parameter, f_{map}, where

$$f_{map} \subset \mathit{Cum}(0.6,0.7,0.8,1.0,1.2,1.3,1.4).$$

(*Cum* specifies a standard cumulative probability distribution defined in Appendix I.)

Average Fracture Porosity. Effective fracture porosity in the area of open fractures is not known. The total of all analysed core from the Waihapa well has been calculated to average 0.13% porosity. However, this value excludes the absence of open fractures in the Waihapa-6 well (porosity=0%) and the effective linear porosity of 1% observed during the drilling of Waihapa-6a and Toko-1. (During the drilling of both of these wells the bit was observed to fall by 2m ~ porosity=1% in 200m of Tikorangi limestone). Fracture aperture imaging (FMS) in the borehole is generally limited to calculating apertures of less than 1mm in size. The fractures contributing the most porosity in the Waihapa wells are much larger than this with oil stained open fractures of greater than 16mm being observed in core. Generally, core derived fracture porosity is dominated by relatively few fractures. In Waihapa-2, four fractures have an individual porosity contribution greater than 0.01% porosity, but these four fractures account for around 68% of the total porosity. The largest frequency of occurrence is the size class 0.001–0.0001% porosity, but these fractures contribute less than 5% to the total porosity. Core porosity ranged from 0% to 0.198%; FMS porosity ranged from 0.12% to 0.56%; drilling porosity ranges from 0% to 1% based upon drilling breaks. Various

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