CHAPTER 2

LITERATURE REVIEW

Extensive studies have been done to understand the behavior of commingled reservoirs. Commingled reservoirs are not uncommon. A large number of fields worldwide have been producing from two or more layers with different reservoir characteristics. A number of papers have been written on the development of alternative approaches in analyzing the production performance and predicting the OGIP of each layer in the commingled gas reservoirs. The most recent ones are discussed in this section.

2.1 Multi-layered Commingled Reservoirs

Commingled reservoirs can be defined as those reservoirs consisting of two or more non-communicating layers. In these reservoirs, the layer communication or fluid transfer from one layer to the other occurs only through the wellbore.

Lefkovits *et al.*[3] has investigated the performance of wells in a commingled reservoir in terms of production response, pressure drawdown, pressure buildup and skin effect. In general, the pressure drawdown response of a well producing from a commingled reservoir is similar to that of a well producing from a single-layer reservoir. The principal difference is that the transient period for commingled reservoirs is much longer than single-layered systems. Although the total production q_T is constant (a basic assumption in his model), each layer will deplete at different rates during the transient period depending on the diffusivity of each layer. Consequently, the average pressure of each layer, p_j will be different as will the rate of change in average pressure during this transient stage. This phenomenon is known as differential depletion. When the rate of change of the well pressure with respect to time becomes constant, the production rate from each layer becomes constant as well.

It is at this stage that the pseudo-steady state is finally attained in the reservoir. The time for the onset of pseudo-steady state was found to be in the order of 50 times as great as that of a corresponding single-layer reservoir.

The pressure build-up behavior of multi-layered commingled reservoir can also be compared to a single layer reservoir. Fig. 2.1 presents a typical theoretical pressure build-up curve obtained for a two-layer reservoir and displays the well established characteristics discussed by Lefkovits *et al.*

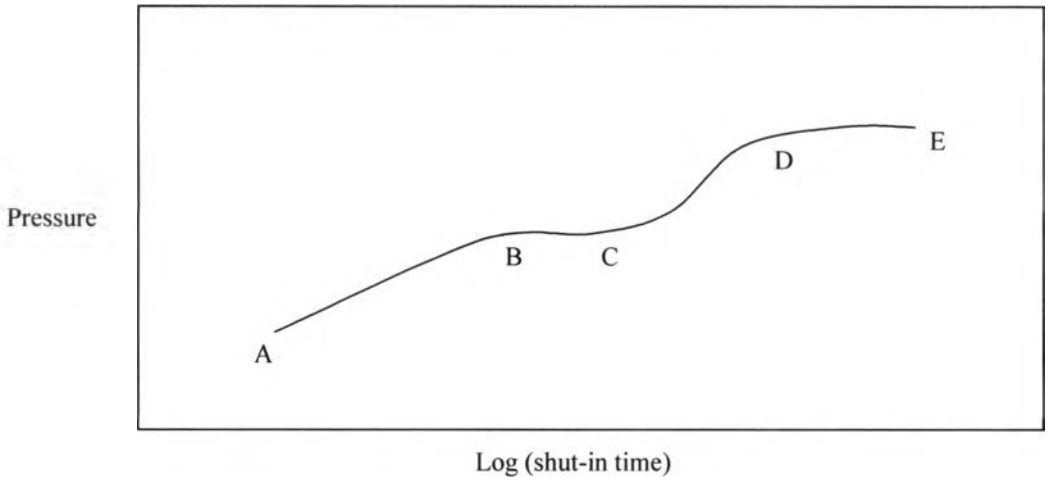

Figure 2.1: Pressure build-up profile for a layered reservoir.

As in a single-layer reservoir, section AB represents the initial semi-log straight line from which reservoir properties such as *kh* can be determined. After the straight-line portion, section BC reflects the leveling-off of the curve similar to a single layer system reaching its average reservoir pressure. This period is followed by another rise in pressure (section CD) which represents the repressurization of the more depleted permeable layer. Another period of leveling-off occurs from point D to E. Point E represents the true average reservoir pressure of the system. The magnitude of the pressure rise during the portion CDE of the pressure build-up curve depends on the contrast of the properties of the layers. If the two layers are nearly equal in permeability, the pressure rise will be small, whereas if the two layers differ widely in properties, the pressure rise will be considerable.

Similarly, the shut-in time required is comparable to the long time needed to attain pseudo-steady state in a commingled system. Thus, wells producing from a multi-layer reservoir need to be shut-in considerably longer than a single layer reservoir in order to obtain useful build-up data (e.g., the static reservoir pressure of the system).

Kuppe and Chugh[4] attempted to simulate this build-up response using typical parameters observed in Australia's Cooper Basin wells. The buildup response was simulated using a three-layer model: the well has two permeable layers separated by an impermeable layer. The more permeable layer has a *kh* of 50 md-ft while the less permeable layer has a *kh* of 5 md-ft. The buildup response showed that it requires approximately 100 years to attain the average reservoir pressure before the pressures equalized between the layers.

With regards to skin, Lefkovits *et al.*[3] demonstrated how skin affects differential depletion between layers in a two-layered reservoir. The characteristics of the reservoir studied are:

$$\frac{k_1}{k_2} = 10$$

$$\frac{h_1}{h_2} = 10$$

$$\frac{\phi_1}{\phi_2} = 1$$

$$\frac{r_e}{r_w} = 2000$$

From the study, it was shown that there is less differential depletion if skin is present or is higher in the more permeable layer compared to the case where both layers have no skin. Consequently, there is more differential depletion if skin is present or is higher in the less permeable layer compared to the case where there is no skin. This is readily explained by the fact that higher resistance in the more permeable layer will tend to equalize the flow from the layers and thus, will reduce differential depletion.

During pressure build-up, there is a difference in the skin effect between multi-layer and single layer reservoirs. For a single-layer reservoir, the skin effect is only evident during the early period of the shut-in time. For multi-layered reservoirs, the effect of skin is present during the entire shut-in time. This is again explained by the differential depletion phenomenon for commingled reservoirs where cross-flow from one layer to the other occurs during the whole shut-in period with the skin acting as a resistance to flow.

Fetkovich *et al.*[5] published the first actual field case study of depletion performance of a layered gas reservoir without crossflow. Using type curve matching, he obtained a depletion decline exponent b of 0.89 (field wide and individual wells). Typically, a gas well producing from a single homogeneous layer at a flowing wellbore pressure of nearly zero has a maximum depletion decline exponent of 0.5. This b value approaching unity is due to differential depletion, a characteristic of a layered reservoir without crossflow.

Using a two-layer model, he plotted the individual and total system p/z versus the total commingled cumulative production from all layers at different permeability ratios, layer volume ratio and layer skins. The following conclusions are drawn from the study:

(1) For any given permeability ratio, depletion is identical for both layers at various layer volume ratio as long as skin on both layers are equal. When the permeability between the two layers are equal, both layers will deplete equally and the system behaves like a single layer. As the permeability contrast becomes high, differential depletion becomes more pronounced.

(2) Values of composite depletion decline exponent b between 0.5 to 1 for gas reservoirs suggest a layered reservoir system. The magnitude of b may provide an indication of the permeability contrast and volume ratio of the layered reservoir.

(3) Different combinations of layer skins can exhibit similar rate-time and pressure-cumulative production response

(4) Shut-in pressures obtained for layered reservoirs will track the pressure of the most permeable layer. Extrapolation of a shut-in p/z vs G_p curve may possibly underestimate the total gas in place at early times and overestimate it at late times.

(5) Similarly, semilog extrapolation of early rate/time data will underestimate recoverable reserves; extrapolation of the late rate-time data may overestimate recoverable reserves.

2.2 Recently Developed OGIP Calculation Techniques

As both conventional material balance and decline-curve analyses pose limitation in estimating gas reserves in commingled reservoirs, extensive studies have been made to explore techniques or methods to accurately predict gas in place in the last decade.

Several authors have investigated the production performance of multi-layer, no cross flow gas reservoirs and proposed methods or techniques in estimating gas reserves.

Fetkovich *et al.*[5] introduced the advanced decline curve analysis in 1973 and has been used by several investigators since for estimating reserves including that of commingled reservoirs. This method combines the analytical pressure solution of the diffusivity equation (early-time transient period) with the Arps empirical equation (later-time depletion period) into a series of log-log plots of dimensionless rates versus dimensionless time. With both transient and pseudo-steady state periods represented, the entire production data for a well can be used in the matching process. The advantage of the Fetkovich type curves over conventional decline curve analysis is that it allows the transient period to be identified and ensures that only the decline portion of the production history is used for reserves estimation and forecasting.

Guardia and Hackney[6] in 1991 presented a method to estimate the original gas in place during the early stage of a field development by integrating the material balance and the advanced decline curve analysis (Fetkovich type curve). Their study is based on the early field data from the South Wilburton Field in Oklahoma.

The methodology used extrapolated static reservoir pressures obtained from conventional 24 to 48-hour shut-in time in the material balance equation to get the OGIP estimate. The OGIP from this approach was compared to the OGIP determined from the Fetkovich type curve match.

For the material balance approach, the pressure is measured at the surface by a high-resolution digital pressure logger that records pressure during production and shut-in periods. The pressure response data, corrected to bottomhole conditions, is then curve-fitted to arrive at an equation that best characterizes the pressure response with time. The curve fit equation normally takes the form:

$$p = yt^{x} + C \tag{2.1}$$

where

y = empirical curve fit constant

x = empirical curve fit exponent

C = flowing bottomhole pressure before shut-in

In order to get the stabilized pressure during the shut-in period, the stabilized time must be determined accurately. This time represents the time at which the pressure response is felt in the reservoir radius and is critical in determining the correct static reservoir pressure. The equation for the stabilized time is given by:

$$t_s = \frac{r_e}{4\eta} \tag{2.2}$$

To determine this time value, the diffusivity constant and the drainage radius should be known. The equation for the diffusivity constant is given by:

$$\eta = \frac{2.637 \times 10^{-4} k}{\phi \mu c_t} \tag{2.3}$$

The diffusivity constant is calculated either from the initial pressure transient test performed after completing the well or from the reservoir parameters determined from the decline curve analysis. The drainage radius is also taken from the decline curve analysis.

The OGIP calculated from the extrapolated material balance solution is then compared to the OGIP obtained from the decline curve analysis using Fetkovich type curves.

Prabowo and Rinadi[7] presented a method to approximate production for each layer in a commingled gas reservoir with unequal initial reservoir pressure using numerical reservoir simulation. The reservoir simulation model used in their study is a rectangular three-dimensional grid system consisting of homogeneous, isotropic layers filled with single-phase gas. They run two simulated cases: one for a two-layer case and one for a five-layer case.

The result from the simulation is then used to model the production performance of actual field cases of a two-layered and a five-layered commingled reservoirs. By using the reservoir properties used in the simulation and the pressure response of each layer at each time step obtained from the simulation runs, the production rate and cumulative production ratios of the actual field cases were calculated.

The equations used to calculate production ratio, Rq and the cumulative gas production ratio, RQ, are given as follows:

$$Rq_k = \frac{\left[Ckh\left(p^2 - p_{wf}^2\right)/\mu z\right]_k}{\sum_{k=1}^{n}\left[Ckh\left(p^2 - p_{wf}^2\right)/\mu z\right]_k} \tag{2.4}$$

where

$$C = \frac{0.703}{T\left[\ln(r_e / r_w) - 1/2 + s\right]} \tag{2.5}$$

and

$$RQ_k = \frac{\left[V / T(p_i / z_i - p / z)\right]_k}{\sum_{k=1}^{n}\left[V / T(p_i / z_i - p / z)\right]_k} \tag{2.6}$$

where

h	=	formation thickness, ft
k	=	permeability, md
p	=	reservoir pressure at current condition, psia
p_i	=	initial reservoir pressure, psia
p_{wf}	=	flowing bottomhole pressure, psia
r_e	=	drainage radius, ft
r_w	=	wellbore radius, ft
Rq	=	production ratio
RQ	=	cumulative production ratio
s	=	skin factor
T	=	temperature, deg F
V	=	reservoir volume, cu. ft.
z	=	gas deviation factor
μ	=	gas viscosity

and the subscripts

k	=	individual layer property
n	=	number of layers

For the actual field cases, the calculated rate from each layer was compared against the rate obtained from production logging. There were some differences from the calculated rates and the rates predicted from PLT. They concluded that production logging may be used to estimate allocation from each reservoir and is valid at that time it was done. As the reservoir depletes, the production allocation changes with time.

West and Cochrane[8] also used the Fetkovich type curve matching and the extended material balance (EMB) techniques to determine reserves in the Medicine Hat Shallow Gas Field, a tight and shallow gas reservoir producing from three commingled zones.

The EMB combines the volumetric gas reservoir material balance with the gas-deliverability equation for solving initial gas in place. It is an iterative process for obtaining an appropriate p/z vs G_p that would result to a constant gas performance coefficient C.

The gas deliverability equation is given by the equation:

$$q(t) = C(t)\left(p^2(t) - p_{wf}^2(t)\right)^n \tag{2.7}$$

where C is the gas performance coefficient defined as:

$$C(t) = \frac{0.703 \times 10^{-3}\, kh}{zT\mu\left(\ln 0.606 \dfrac{r_e}{r_w}\right)} \tag{2.8}$$

where

C = gas performance coefficient

h = formation thickness, m

k = permeability, md

n = exponent of backpressure

p = pressure, kPa

p_{wf} = flowing bottomhole pressure, kPa

$q(t)$ = flowrate at time t, m^3/d

r_e = drainage radius, m

r_w = wellbore radius, m

T = reservoir temperature, R

z = gas deviation factor

μ = gas viscosity

Note that the terms making up the coefficient are either fixed reservoir parameters (k, h, r_e, r_w and T) which do not vary with time or terms that vary with temperature, pressure and composition (z and μ_g). Typically, formation temperature and gas composition do not vary significantly in a dry gas reservoir, so the latter terms are mainly affected by pressure. Owing to the low initial reservoir pressure of the formation studied by the authors (shallow formation), the difference between the initial and the abandonment pressure is not significant. Hence, the variation in the pressure dependent terms of the gas performance coefficient C is considered constant.

Another simplification to the equation that the authors made was to assume that n is equal to 1. This is because of the very low production rates seen from the wells; hence, only laminar flow regime exists.

Hence, the final gas deliverability equation is:

$$q(t) = C\left(p^2(t) - p_{wf}^2(t)\right) \tag{2.9}$$

With this simplification, the sum of the instantaneous production rates (cumulative production or G_p) can be related to the reservoir pressure similar to the material balance equation. The EMB method involves iterating to find the correct p/z vs G_p relationship that will give a constant C with time.

From this study, both the Fetkovich type curve matching and the EMB proved to be accurate in estimating OGIP and providing accurate production forecasts for the tight, shallow gas reservoirs of Medicine Hat Field.

Kuppe and Chugh[4] developed a simple spreadsheet model to estimate the layer productivity and OGIP of wells in tight multi-layered gas reservoirs. The technique basically groups the high permeability (high *kh*) layers into one "high permeability model layer" and the low permeability (low *kh*) layers into one "tighter model layer". The model was applied to wells in Australia' Cooper Basin Field to confirm the technique.

The technique combines the material balance and the gas flow equations for the model layers and are given as follows:

Material Balance Equation:

$$\left(\frac{p}{z}\right)=\left(\frac{p}{z}\right)_i\left(1-\left(\frac{G_{p1}(t)+G_{p2}(t)}{G_1+G_2}\right)\right) \tag{2.10}$$

Gas Flow Equation:

$$q_{gi}=J_g\left(m(p)_i-m(p_{wf})_i\right) \tag{2.11}$$

For multiple layers,

$$q_T(t)=\sum_{k=1}^{n}q_{gk}(t) \tag{2.12}$$

In addition to the two relationships the cumulative gas production is also tracked and is given by the equation below:

$$G_p=\int_0^t q_g(t)dt \tag{2.13}$$

where

G	=	original gas in place, Mscf
G_p	=	cumulative gas produced, Mscf
J_g	=	real gas flow coefficient, Mscf-cp/D/psi2
m(p)	=	real gas pseudo-pressure, psi2/cp
$m(p_{wf})$	=	pseudo-pressure at flowing bottomhole pressure, psi2/cp
p	=	reservoir pressure, psia
p_{wf}	=	flowing bottomhole pressure, psia
q	=	gas production rate, Mscf/d
q_T	=	total commingled flowrate, Mscf/d
t	=	time, days

and the subscripts

i	=	initial
g	=	gas

The matching procedure is started by allocating the stratified *kh's* into high *kh* and low *kh* layers. Layers with $k_{in\text{-}situ} \leq 1.0$ md were considered low permeability layers and layers with $k_{in\text{-}situ} \geq 1.0$ md were considered high permeability layers. With the well's bottomhole pressure history, production history and recorded buildup pressures known, the history-matching is done using plots of p/z for each layer versus total cumulative production and cumulative production versus time (for each layer and the total production).

Last[9] presented another approach in predicting the OGIP of the component layers in a commingled gas reservoirs called the Commingled Wellbore Model (CWM). The model basically calculates the original gas in place of each individual reservoir from the volumetric gas, material balance and inflow performance equations. The OGIP is a function of reservoir pressure, layer thickness, porosity, water saturation, temperature and area. An estimate of the area is input in the model in order to generate a production history of the well over time that will match the actual flow rates and measured pressures from the well. The areas are adjusted repeatedly until the best match is obtained. The individual reservoir areas used to achieve the most satisfactory match are then converted back to gas volume using the known reservoir pressure, thicknesses, porosities, water saturation and temperatures.