Condensate banking vs Geological Heterogeneity – who wins?

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Outline

• P-T diagram of Gas reservoirs
• Diffusion equation linearization using gas pseudo pressure
• Pseudo pressure in gas condensate reservoir
• Well test signature of the gas condensate reservoir (Analysis procedure)
• Interfering of geology and fluid
  – Production time
  – Production rate
  – Correlation length
  – Vertical permeability
  – Reservoir stripping of heterogeneities
• GOR>3300 scf/STB to very higher values 150000 scf/STB
  • if GOR >50000 \(\rightarrow\) small condensation in the reservoir
• API \~ 40 to 60 and increases as pressure follows dew point
• Lightly coloured
Linearization of diffusion equation

• **Dry gas reservoir**
  – Viscosity = f(p)
  – Compressibility = f(p)
  – Linearization using single phase pseudo pressure
    • The well-test theory can be applied (single phase liquid)

\[
m_p = 2 \int_{p_0}^{p} \frac{p dp}{\mu_g z_g}
\]
Gas condensate reservoirs

- **Two-phase pseudo pressure**

\[
m(p) = 2 \int_{p_0}^{p} \left( \frac{\rho_o k_{ro}}{\mu_o} + \frac{\rho_g k_{rg}}{\mu_g} \right) dp
\]

\[
m(p) = 2 \int_{p_0}^{p} \left( \frac{k_{ro}}{\mu_o z_o} + \frac{k_{rg}}{\mu_g z_g} \right) p dp
\]

The pseudo-pressure is evaluated based on:

- **Steady state assumption** (O’Dell and Miller, 1966): A model composed of a far region \( P > P_{dew} \) and a near wellbore region \( p < p_{dew} \) when both fluids flowing

- **Fevang and Whitson assumption** (1996): The existence of an intermediate region where condensate is immobile.

- **Gringarten assumption** (2000): The existence of a forth region in immediate vicinity of wellbore (velocity dependent relative permeability)

- **Single-phase pseudo pressure** (Al-Hussainy et al. 1966)

\[
m(p) = 2 \int_{p_0}^{p} \frac{pd p}{\mu_g z_g}
\]

- Assuming immobile condensate
Two-phase or single phase m(p)

• **Two-phase m(p)**
  – Advantages: Remove the fluid heterogeneity effect
  – Disadvantages: Highly dependent on relative permeability data (a small error in relative permeability data provide higher error than using a single-phase pseudo pressure), relative permeability data as a function of pressure, evaluation of two-phase pseudo pressure function, needs accurate PVT modelling, inaccuracy to model the realistic phenomena,…

• **Single phase m(p)**
  – Advantages: Easy to apply, the Total skin, Mobility ratio and two-phase skin can be estimated
  – Disadvantages: The assumption of zero-condensate mobility may not be appropriate, the radial composite model may not be seen in short tests…
  – Approach: assuming a two-region radial composite model.
Gas condensate interpretation method using single phase pseudo-pressure

\[ S_T = 1.151 \left[ \frac{m(p_{ws@1hr}) - m(p_{wf@1p})}{m} - \log \frac{k_{out}}{\varphi \mu_{out} c_{l_{out}} r_w^2} + 3.23 \right] \]

or

\[ S_T = \frac{1}{M} S_m + \left( \frac{1}{M} - 1 \right) \ln \frac{R}{r_w} \]

or

\[ S_t = \frac{S_m}{k_{rg}} + S_{2p} \]
A realistic pixel-based model of a commingled (i.e. $k_v=0$) multi-facies, high net:gross, braided fluvial reservoir with $86\times48\times25$ cells (each cell: $25m\times25m\times1.9$).

- We used a real case ten-component rich gas condensate fluid with a maximum liquid dropout of 30.
- A tuned PR Equation of State was used to model the fluid behaviour.
Native pseudo-pressure derivative response: heterogeneous model single-phase fluid

- Single phase Pseudo pressure test response (geological behaviour)
- Draw-down and build-up shows a deflection at the late time region (Boundary effect)
- The early time deflection is due to a Fake Wellbore Storage arising from the coarse cell penetrated by wellbore
- The time at the end of FWBS can be estimated as (Blanc 1999)

\[ t \geq 2.6 \Delta L^2 \times \frac{\phi \mu \alpha}{k} \]
Native pseudo-pressure derivative response: homogenous model, two-phase fluid system

A) When two stabilizations present

- $S_t = S_m + S_{2p}$
  1. First stabilization $\rightarrow S_m$
  2. Second Stabilization $\rightarrow S_t$

B) When only one stabilization (second) presents (e.g. due to WBS)

- $S_t = S_m + S_{2p}$
  1. Second Stabilization $\rightarrow S_t$
  2. Correlation $\rightarrow S_{2p}$
Kernel function (Build-up explanation)

Sensitivity coefficients (Drawdown Explanation)

The logarithm of well pressure sensitivity with respect to local permeability field at the early time (left) and at the late time (right).

\[
\Delta P(t) = \frac{P(t,k_1,k_2,...,k_m + \delta k_m,k_{m+1},...,k_n) - P(t,k_1,k_2,...,k_{m-1},k_m,...,k_n)}{\delta k_m}
\]

\[
\sqrt{r_D} G(r_D,t_D) = 0.5 \sqrt{\frac{\pi r_D^2}{t_D}} \exp\left(-\frac{r_D^2}{2t_D}\right) W_{1/2,1/2}\left(\frac{r_D^2}{t_D}\right)
\]
Analytical-Numerical combination:  
WT history matching

- Create a model with Log-normal distr.
- $\Delta x = \Delta y = 10$ ft. (2000ft*2000ft*25ft$^3$)
- Follow the methodology described here
- Calculate the analytical Kinst (Feitosa 1994)
- Plot both kinst (Numerical and Analytical)

**Results:**
Can be used in well test history matching to skip simulation 😊

$$A_{ring} \times \ln K_{ring} = \sum_i A_i \times \ln K_i$$

Layer 1:
$$\frac{1}{k_{int}(t)} = \sum_{disk=j} W_{ji} \times \frac{1}{k_{ringj}}$$

Layer 2:
$$\frac{1}{k_{int}(t)} = \sum_j W_{jt} \times \frac{1}{k_{ringj}}$$

Total:
$$K_{int}(t) = Power\_Average\_of(k_{intLAYER}(t))$$
The wellbore pressure always remains sensitive to any potential permeability changes in near wellbore area.
Interfering effect of the geological and the production parameters: combined geology vs. fluid signatures:

Effect of Production Rate on drawdown & subsequent build-up

- Fluid + FWBS
- Fluid & geology
- Layered

**Corr. Length = 250m**
**Drawdown time = 4 Days**

- BU with rate 5MMscf/d
- BU with rate 30MMscf/d

- DD with rate 30MMscf/d
- DD with rate 5MMscf/d

- Rate = 20MMscf/d
- Corr. Length = 250 m
- Drawdown Time = 4 Day
- \( P > P_{\text{dew}} \)

- Liquid drop-out effect
Interfering effect of the geological and the production parameters:
combined geology vs. fluid signatures:
Effect of Production Time on Subsequent Build-up
Interfering effect of the geological and the production parameters: combined geology vs. fluid signatures:

Effect of Correlation length

- Rate = 20 MMscf/d
- Corr. Length = 750 m
- Drawdown Time = 4 Days

- Fluid + FWBS
- Fluid & Geology
- Layerd

\[
\Delta m(p) & \Delta m'(p)
\]

Time, hr

- Drawdown
- Build-up

- Fluid effect
- Geology
- Ramp effect
Interfering effect of the geological and the production parameters: combined geology vs. fluid signatures:

**Effect of Vertical Permeability**

- The sensitivity of the derivative response with respect to the correlation length decreases in the cases with high vertical permeability.

- Increasing the vertical flow communication between the reservoir layers causes the ramp effect to disappear.
Interfering effect of the geological and the production parameters: combined geology vs. fluid signatures:

**Stepwise homogenization**
Conclusions

• The two-phase pseudo pressure function can theoretically eliminate the fluid heterogeneity effect, however the higher degree of uncertainty in the relative permeability data leads to use the single phase pseudo pressure.

• The condensate drop-out has different signature on build-up and drawdown.
  – The averaging Kernel function and the single phase sensitivity coefficients explain this different signature.
Conclusions

• The production rate has a significant effect on the subsequent build-up response. This complicate the well test response in presence of geological heterogeneity (Ramp)

• The test response has less order of sensitivity than the production rate

• The shorter the correlation length, the higher the condensate signature on the test response

• The higher correlation length compensate the effect of vertical permeability.
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References