Condensate banking vs Geological Heterogeneity – who wins?

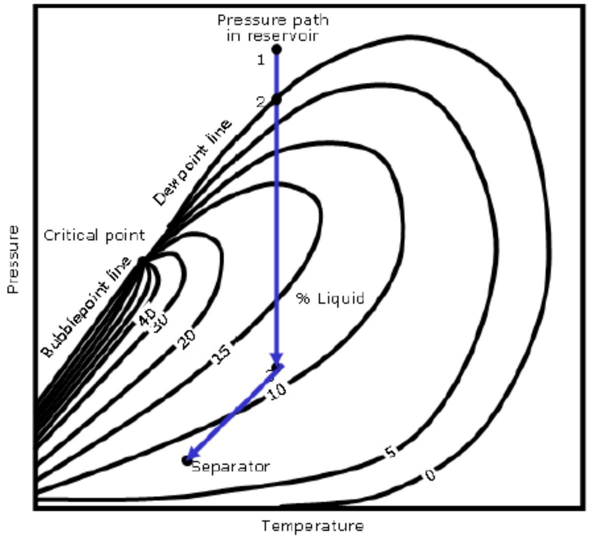
Hamidreza Hamdi
Mahmoud Jamiolahmady
Patrick Corbett

SPE 143613

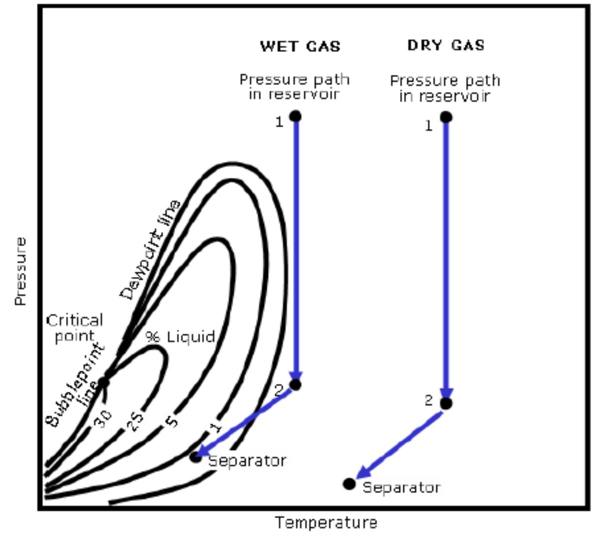
Outline

- 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

P-T diagram of gas reservoirs



Retrograde gas-condensate



Dry and wet gases

- GOR>3300 scf/STB to very higher values 150000scf/STB
  - if GOR >50000 → small condensation in the reservoir
- API ~ 40 t0 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)

$$m_p = 2\int_{p_0}^{p} \frac{pdp}{\mu_g z_g}$$

Gas condensate reservoirs

- **Two-phase pseudo pressure**

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

$$m(p) = 2\int_{p_o}^{p}\left(\frac{k_{ro}}{\mu_o z_o} + \frac{k_{rg}}{\mu_g z_g}\right)pdp$$

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)**

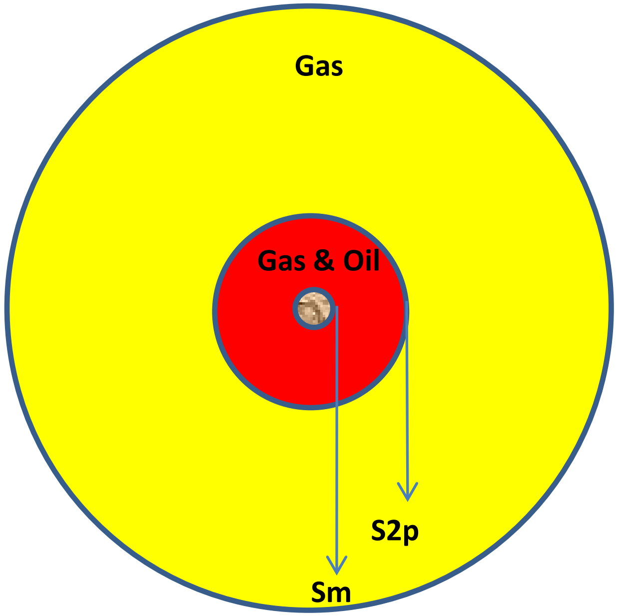
$$m(p) = 2\int_{p_0}^{p}\frac{pdp}{\mu_g z_g}$$

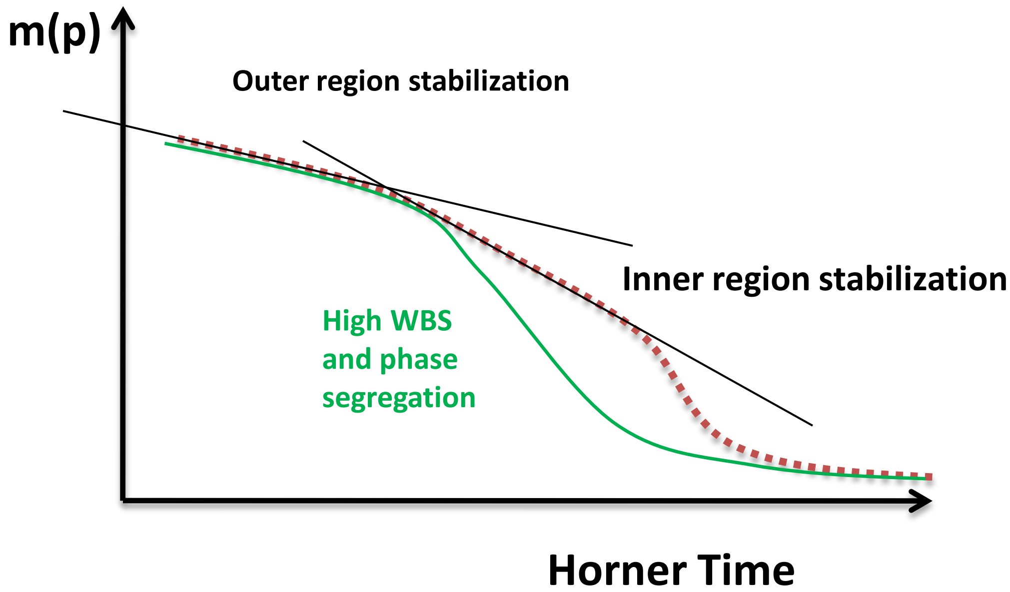
  - Assuming immobile condensate

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



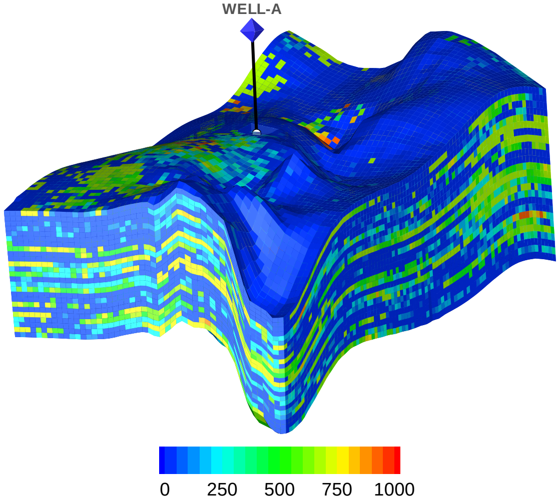


$$S_T = 1.151\left[\frac{m(p_{ws@1hr}) - m(p_{wf@tp})}{m} - \log\frac{k_{out}}{\varphi\mu_{out}c_{t\_out}r_w^2} + 3.23\right]$$

$$S_T = \frac{1}{M}S_m + \left(\frac{1}{M} - 1\right)\ln\frac{R}{r_w}$$ **or** $$S_t = \frac{S_m}{k_{rg}} + S_{2p}$$

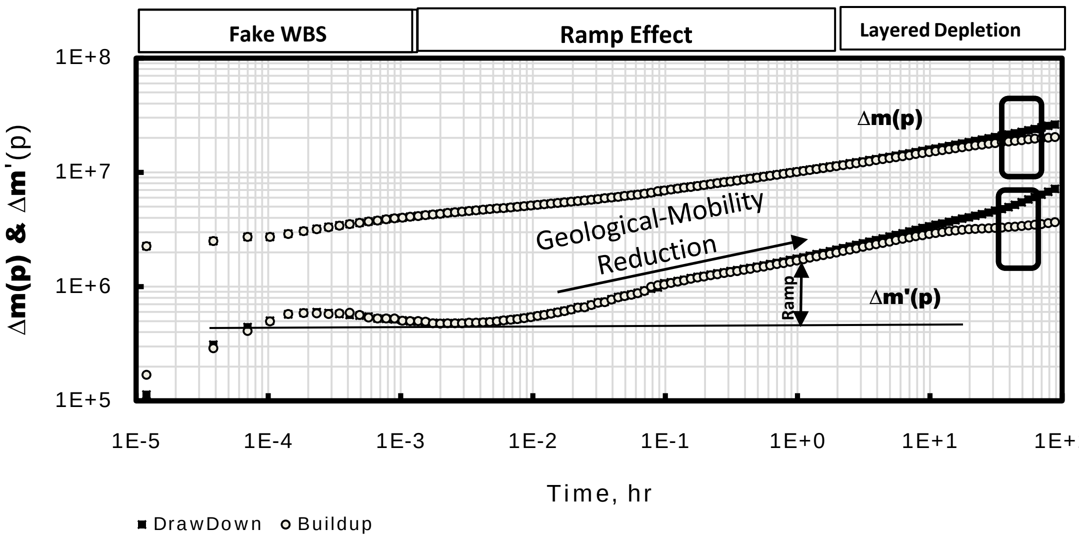
Geological model and the fluid composition

Components	Composition %
CO2	2.97
C1N2	66.67
C1	88
C2	9.68
C3-4	8.39
C5-6	3.12
C7-10	4.83
C10	12
C11-14	1.77
C15-20	1.5
C21-29	0.87
C30+	0.2
Dew Point Pressure (psia)	5341
Maximum liquid drop-out (%PV)	30



- A realistic pixel-based model of a commingled (i.e. k_v=0) multi-facies, high net:gross, braided fluvial reservoir with 86*48*25 cells (each cell: 25m*25m*1.9)
- 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.

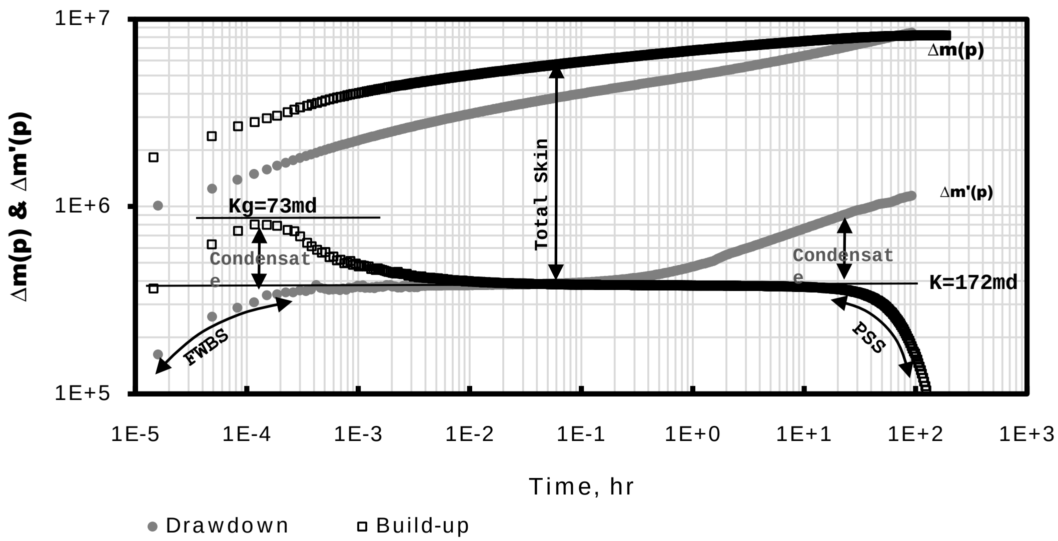
Native pseudo-pressure derivative response: heterogeneous model single-phase fluid



- 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 arrising from the coarse cell penetrated by wellbore
- The time at the end of FWBS can be estimated as (Blanc 1999)

$$t \geq 2.6\Delta L^2 \times \frac{\varphi \mu c_t}{k}$$

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 → S_m**
2. **Second Stabilization → S_t**

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

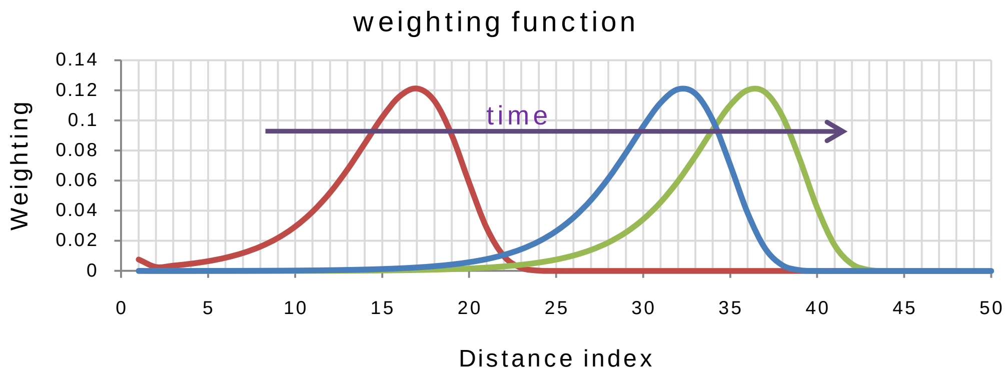
$S_t = S_m + S_{2p}$

1. **Second Stabilization → S_t**
2. **Correlation → S_{2p}**

Native pseudo-pressure derivative response: homogenous model, two-phase fluid system

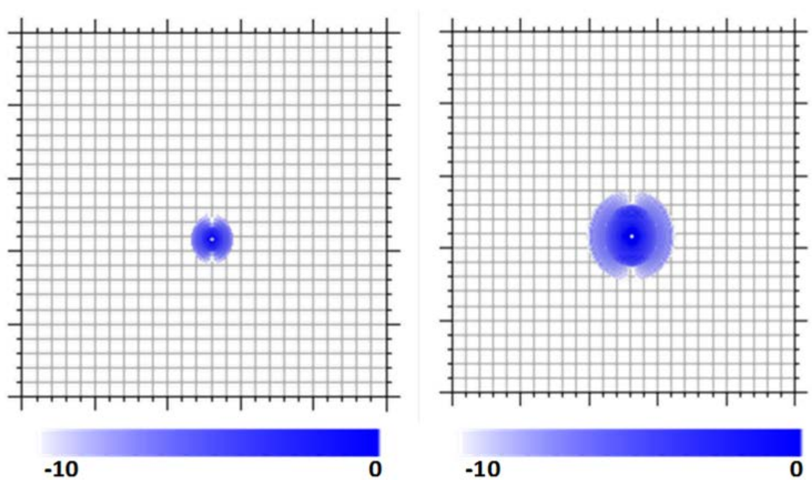
Buildup vs Drawdown

Kernel function (Build-up explanation)



$$\sqrt{t_D}G(r_D,t_D)=0.5\sqrt{\frac{\pi r_D^{2}}{t_D}}\exp\left(-\frac{r_D^{2}}{2t_D}\right)W_{1/2,1/2}\left(\frac{r_D^{2}}{t_D}\right)$$

Sensitivity coefficients (Drawdown Explaination)



$$\frac{\partial P_w(t)}{\partial k_m}=\frac{P_w(t,k_1,k_2,...,k_m+\delta k_m,...,k_n)-P_w(t,k_1,k_2,...,k_m,...,k_n)}{\delta k_m}$$

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

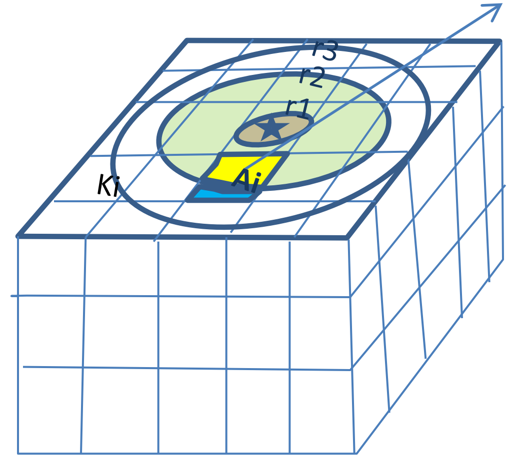
Analytical-Numerical combination: WT history matching

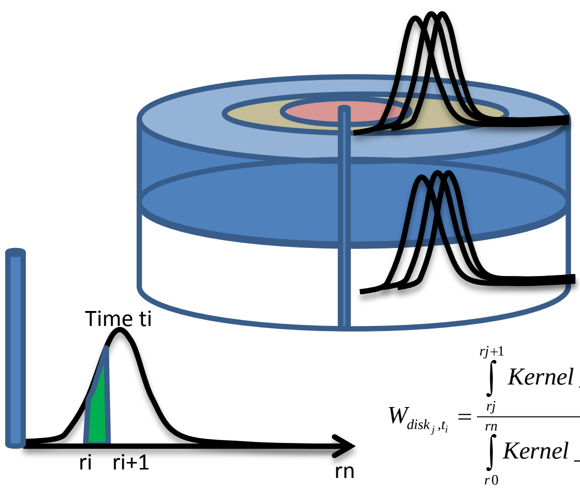
- Create a model with Log-normal distr.
- Δx=Δy=10ft. (2000ft*2000ft*25ft^3)
- Follow the methodology described here
- Calculate the analytical Kinst (Feitosa 1994)
- Plot both kinst (Numerical and Analytical)

Results:

Can be used in well test history matching to skip simulation ☺

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



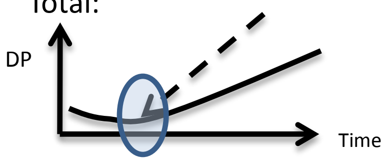


$$W_{disk_j, t_i} = \frac{\int_{rj}^{rj+1} Kernel\_Function(t,r)}{\int_{r0}^{rn} Kernel\_Function(t,r)}$$

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

Layer 2: $$\frac{1}{k_{inst}(t)} = \sum_{j} W_{j,t} \times \frac{1}{k_{ringj}}$$

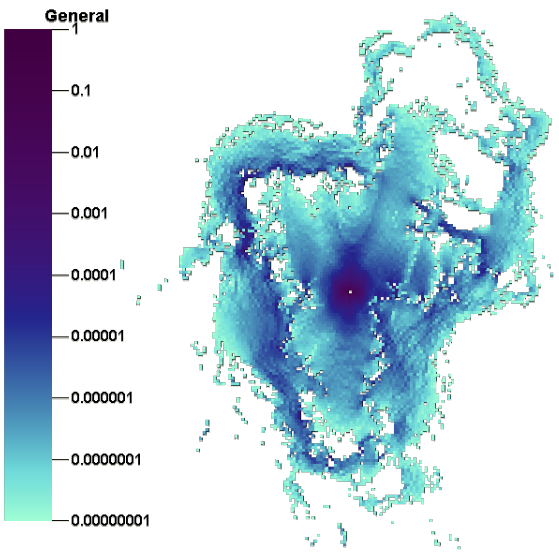
Total: $$K_{inst}(t) = Power\_Average\_of\,(k_{insLAYERK}(t))$$

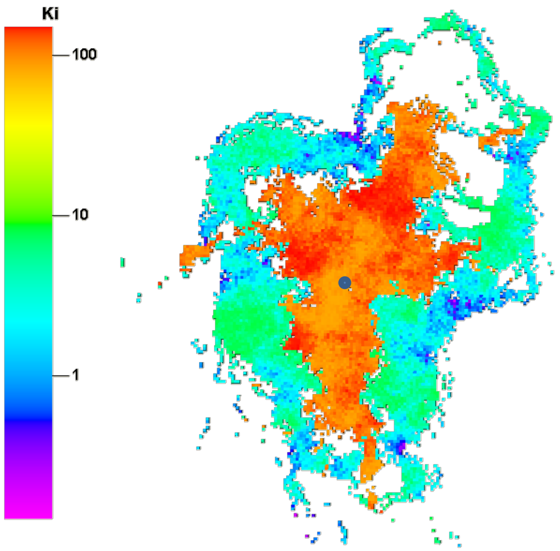


AFES

HERIOT WATT UNIVERSITY

Sensitivity Coefficients





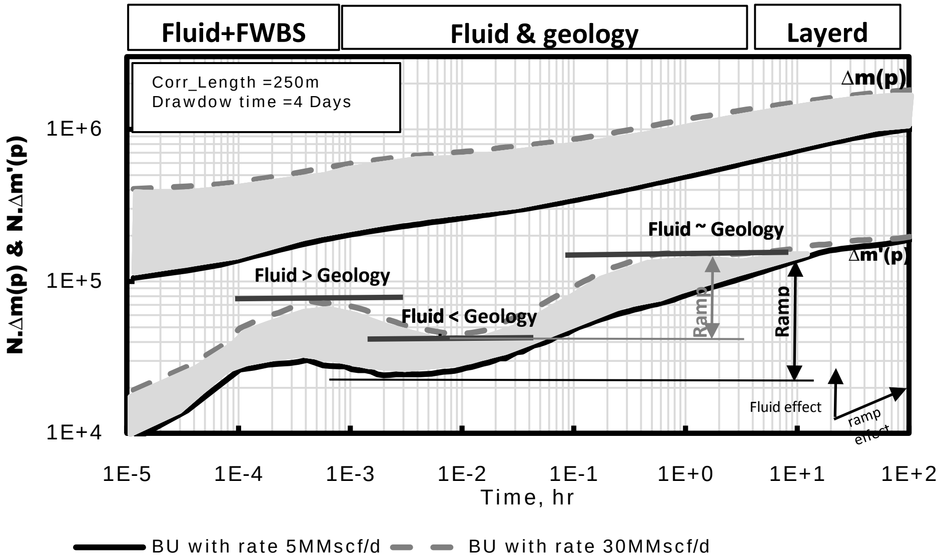
$$\frac{\partial P_w(t)}{\partial k_m} = \frac{P_w(t,k_1,k_2,\ldots,k_m+\delta k_m,\ldots,k_n) - P_w(t,k_1,k_2,\ldots,k_m,\ldots,k_n)}{\delta k_m}$$

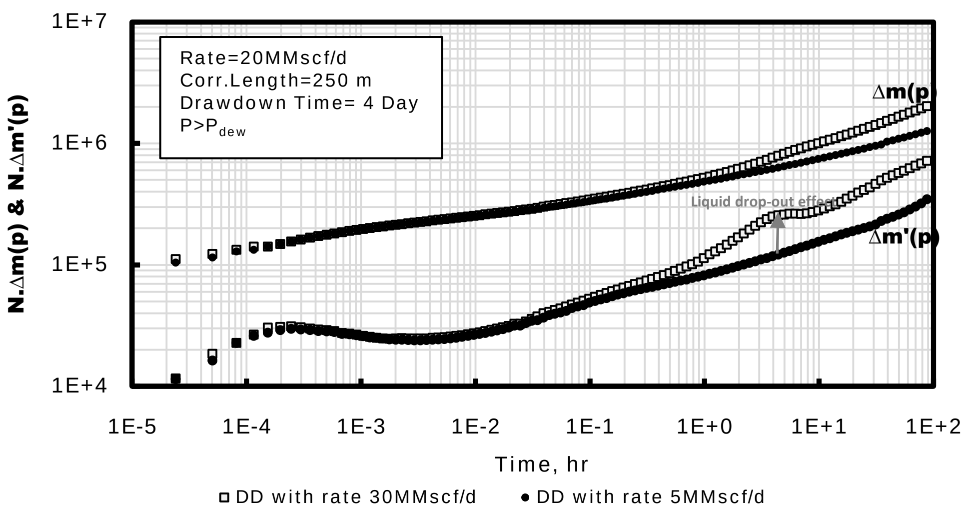
$$\frac{\partial P_d(x_i,y_i,z_i,t_n)}{\partial k_x} = -\frac{c_1}{\mu}\Delta y_m \Delta z_n \int_0^{t_n}\int_{x_{l-1/2}}^{x_{l+1/2}} \left(\frac{\partial P_d(x,y_m,z_n,s)}{\partial x} \times \frac{\partial}{\partial x}\frac{\partial P_{nd}(x,y_m,z_n,t_n-s)}{\partial (t_n-s)} \right) ds dx$$

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 :

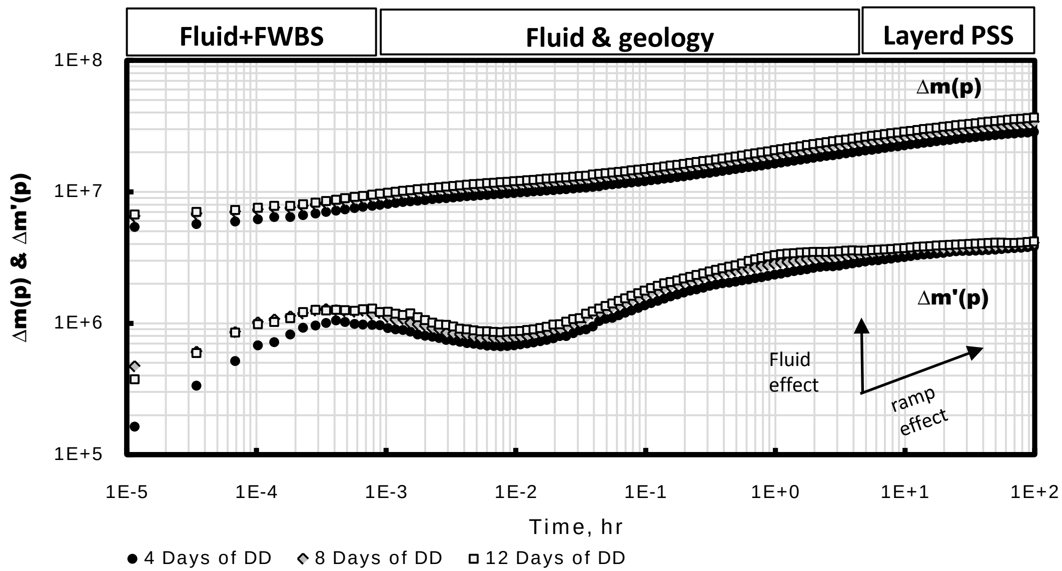
Effect of Production Rate on drawdown & subsequent build-up





Interfering effect of the geological and the production parameters: combined geology vs. fluid signatures :

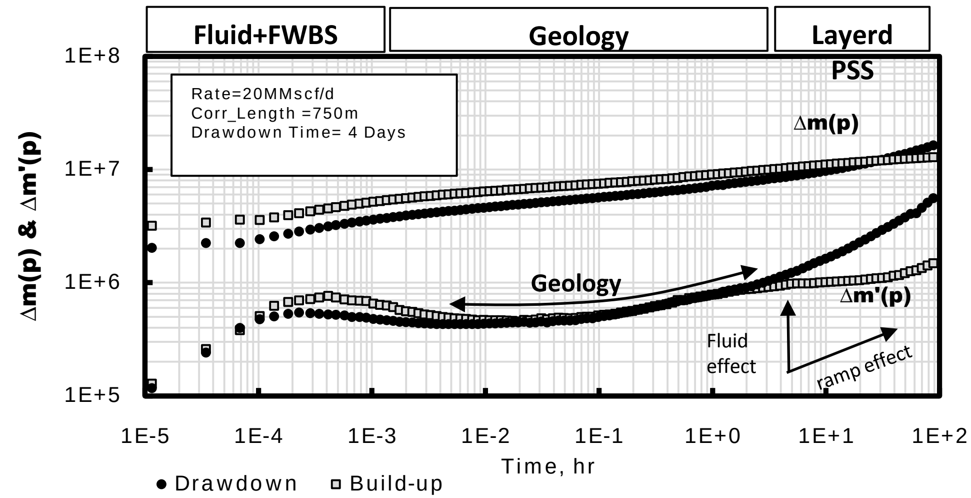
Effect of Production Time on Subsequent Build-up

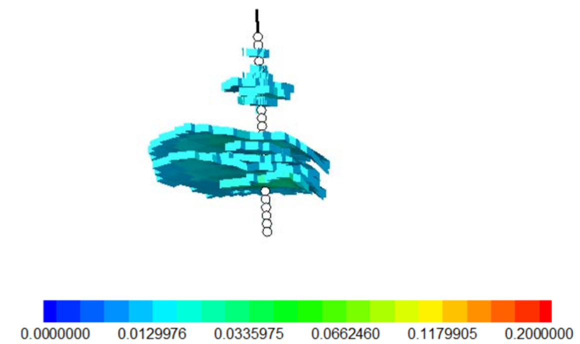


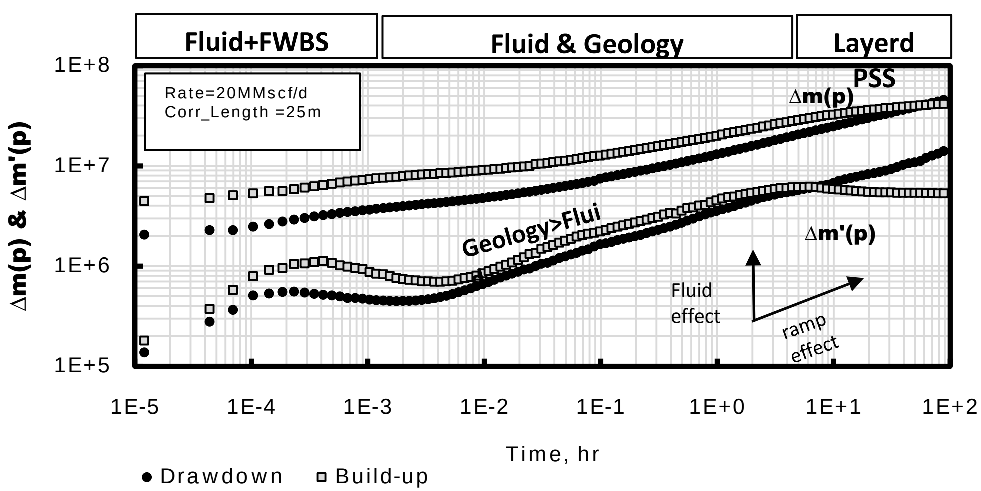
AFES

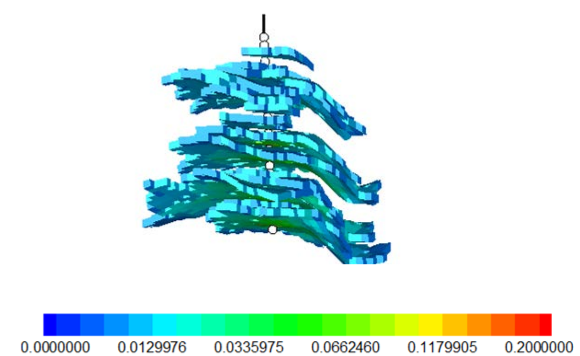
Interfering effect of the geological and the production parameters: combined geology vs. fluid signatures :

Effect of Correlation length



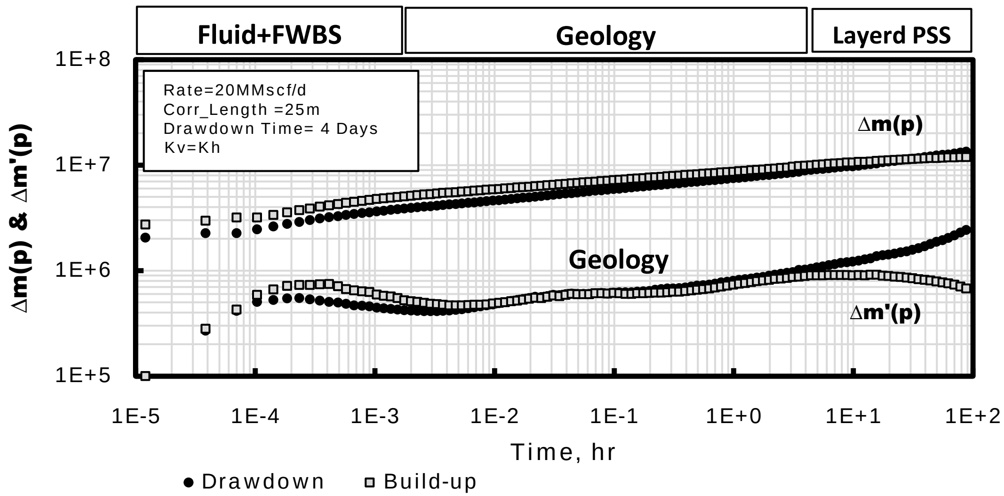


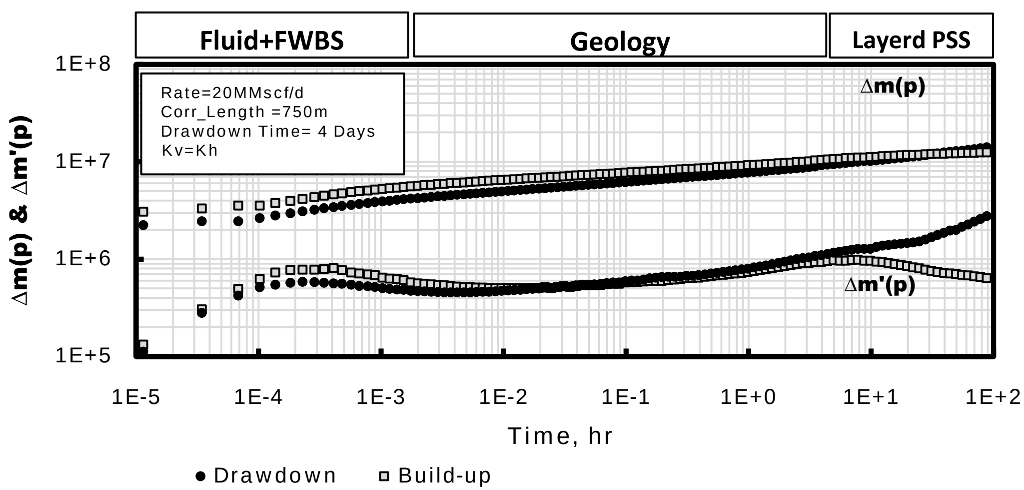




Interfering effect of the geological and the production parameters: combined geology vs. fluid signatures :

Effect of Vertical Permeability



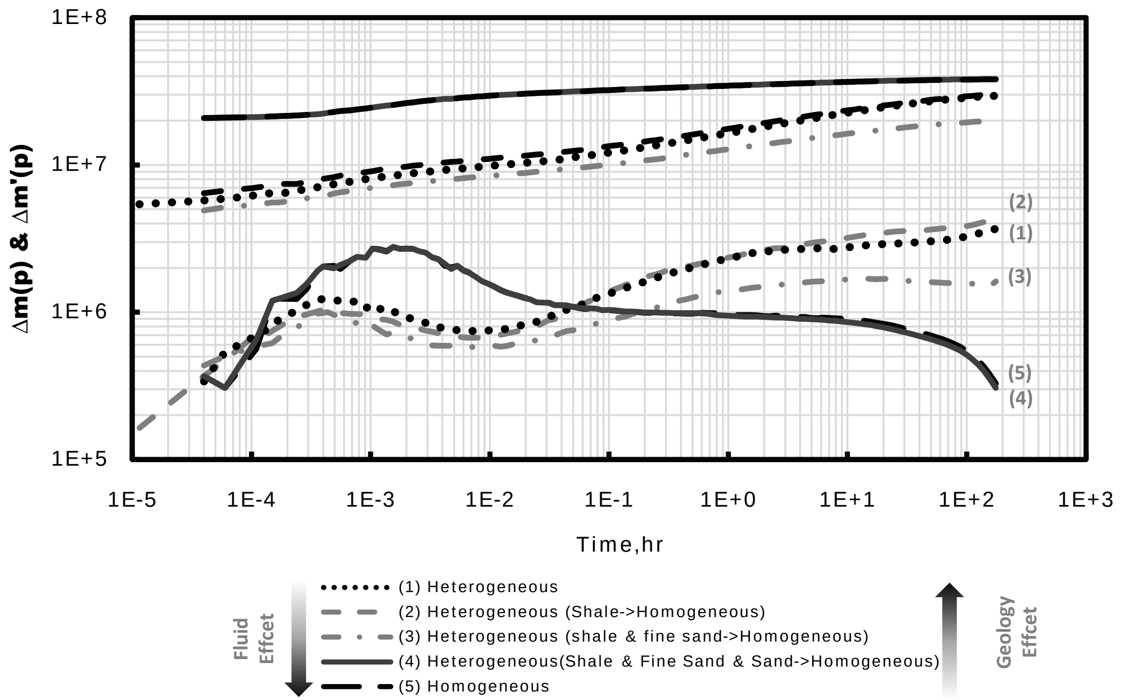


- The sensitivity of the derivative response with respect to the correlation length decreases in the cases with high vertical permeability.

- 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 drwadown
  - 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.

Acknowledgements

- Alaa Sarikouzel (BP)
- Schlumberger (E300, PVTi, E100, FloGrid)
- Kappa (Ecrin)
- Weatherford (PanSystem)
- Total E&P UK ltd

AFES

HERIOT WATT UNIVERSITY

References

- Al-Hussainy, R., Ramey, H. J., and Crawford, P. B.: “The flow of real gases through porous media,” JPT, May 1966, p 624-36.
- Blanc, G., Ding, D.Y., Estebenet, T. And Rahon, D. : “Transient productivity index for numerical well test simulations,” in Schatzinger, R. and Jordan, J., eds.:” Reservoir charactrization: recent advances,” AAPG Memoir 71, 1999, pp 163-174.
- Fevang, O. and Whitson, C. H.: “Modeling gas-condensate well deliverability,” SPERE, November 1996, p 221-230.
- Gringarten, A. C., Al-Lamki, A., Daungkaew, S., Mott, R. And Whittle, T. M.:” Well test analysis in gas condensate reservoirs,” Paper SPE 62920, Presented at SPE Annual Technical Conference and Exhibition, Dallas, Texas,1-4 October 2000.
- He, N.:“ *Three dimensional reservoir description by inverse theory using well-test pressure and geostatistical data*,” PhD thesis, University of Tulsa, 1997.
- O’Dell, H. G. and Miller, R. N.: “Successfully cycling a low permeability, highyield gas condensate reservoir,” Paper SPE 1495, Presented at the SPE 41st Annual Fall Meeting, Dallas, Texas, October 1966.
- Oliver, D. S.: “The averaging process in permeability estimation from well-test data,“ Paper SPE 19845, SPE Formation Evaluation, 5(3), September 1990.
- Raghavan, R.:”Testing under multi-phase flow conditions,” in Kamal, M.M. (eds) :” *Transient Well Testing,”* , Society of Petroleum Engineers, 2009, pp 447-473