Sharing Experiences and Learning's Of Formation Testing

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The focus is on pressure gradients and fluid contacts.

We consider some of the perhaps more unusual issues

- Data QC in an offshore environment
- Quantification of uncertainty in a fluid contact
- Local examples will be shown that illustrate some of the more unusual effects that can cause uncertainty in interpretation of pressure measurements
- Suggestions on optimal pretest volumes will be made

Unless stated otherwise, please assume that any discussion here refers to wells drilled with water based mud.
Gauge Integrity

1. Quartz and Strain gauges should show constant offset

2. Pressure offsets between probes (if a multi-probe job) should be constant (e.g., check before/after mud pressures)

Pressure Stabilisation At End Pretests

1. Expect 3 consecutive identical pressure readings on the quartz gauge (to 2 DP’s)

2. OR (and this is more relevant to formation testing FT from offshore floaters)
   
   1. The magnitude of the 60 second slope should be less than 0.02 psi/min (ideally less than 0.002 psi/min)

   2. The variance of the pressure should be less than 0.01 psi (ideally)
Less Obvious Sources of Error In Pressure Data -1 (regarding gradient and fluid contact determination)

- Pressures from pretests that do not belong to the *Valid Pretest Survey*

- Capillary pressure effects can prevent accurate formation pressure measurement
  - Pretests in strongly water wet reservoirs; most prominent in mid-perm gas reservoirs
  - Pretests taken in gas zones just beneath vertical permeability barriers
    - Particularly bad for points within 3m of the top of a gas zone
    - We see an example later
  - When filtrate has non-zero entry capillary pressure $\text{PC}_{\text{entry}}$
    - WBMF invading a mixed wet/oil wet reservoir
    - OBMF invading a water wet reservoir
    - Varying wettability; can be significant in oil/water transition zones
    - Can try to measure $\text{PC}_{\text{entry}}$ by pretesting before and after sampling
• Tidal effects in formations that are connected to surface water (ie follow the hydrostatic gradient)
  • Estimated to be up to 1 psi in oil/water legs
  • Negligible in gas legs
  • Tidal effects complicate multi-well interpretations (eg normalisation of gauges via measurements taken in an aquifer that is assumed to be in equilibrium).

• Formation fluid in the FT flowline
  • Particularly likely if sampling has occurred, or even large volume pretests in gas zones
Comments On Interpretation Methodology

Regression Model

- Initially assume a straight line model
- Least squares regression where both pressure P and depth Z are variables
- Check bias on error residuals
  - Zonal sub-division warranted?
  - Curved gradient detected (compositional gradient, other effects)?
  - Move to a quadratic or cubic line?

Use a combination of log data, Pressure vs Depth regression and Excess Pressure to delineate gas, oil and water legs

Use a combination of Pressure vs Depth Regression and Excess Pressure To Identify Contacts

Contacts are either Proven (lie in a sand for which there also exist log saturations) or Unproven

Comments on Uncertainty Estimation method next
Estimating Uncertainty In Contacts. Several methods are used - 1

Statistical Error, SE - use the approach of SPE 99386 – Quantitative Estimate

- SE is an estimate of the allowable uncertainty in the contact, assuming that the regression errors are unbiased (ie purely statistical).

Uncertainties also assessed by these other means:

- Observations of oil, gas or water at various depths – a qualitative estimate
  - Log saturations
  - Sampling or Pumping stations
- Determining in the contact depth and associated uncertainty, by constraining the “pressure gradient” with the independently determined expectation of formation fluid density and its associated uncertainty - a qualitative estimate
A few guidelines on applying the different types of Uncertainty estimates

1) If the contact is Proven, then it is possible to choose as follows:
   - Uncertainty = MIN(Qualitative, Quantitative)

2) If the contact is Unproven, then it is advisable to carry both Qualitative and Quantitative uncertainty estimates
Objective: To show how tidal corrections are potentially important when interpreting wireline measured pressure data taken in an oil or water zone

Demonstrate this by a case study on a well X

The formation testing tool discussed here will be called the MDT, for the sake of convenience

But, the example could refer to data from almost any formation testing tool
**Tidal effects on reservoir pressure** – estimated to be up to 1 psi, based upon various sources

Examples for oil fields; Peak to Trough Magnitude

- More than 1 psi is observed by some permanent gauges of an oil field
- An effect of 0.25 psi was inferred from a well test in an oil field
- Values of up to 1.2 psi have been measured in the Jabiru field (SPE 14607)
- Values Of Up To 1.5 psi have been reported for North Sea oil fields (See Smit & Sayers, World Oil 2005 or SPE 23142)
Gas reservoirs (and gas caps) typically show much less tidal effect. For example:

- 0.025 psi is predicted for the Ormen Lange gas field (refer SPE 95763).
  - The value rises to 0.13 psi if water enters the field.
- In Jabiru (SPE 14607) Tidal $\Delta P_{\text{gas\_cap}}$ can be less than 10 times $\Delta P_{\text{oil\_zone}}$ or $\Delta P_{\text{water\_zone}}$.

With respect to the time lag between sea floor and reservoir, SPE 14607 reports that:

- For some North West Australian Oil Water reservoirs (with no gas cap) time lags of typically less than 15 minutes have been calculated.
- For some gas/oil/water systems, oil zone time lags can be up to 30 minutes.
- Such values should be similar to those in Carnavon oil reservoirs.
  - Typically the observed time lag is minimal (order of 10 minutes).
The total tidal effect $\Delta e_t$, is caused by three main effects:

- **solid earth tide dilatation**, $\Delta E$,
- **the barometric tidal dilatation** $\Delta B$,
- **ocean tide dilatation** $\Delta O$,

\[ \Delta e_t = \Delta E + \Delta B + \Delta O \]

The ocean tide is the dominant source of perturbation (SPE 14607).

For the remainder of this discussion we only consider Ocean Tide Effects, $\Delta O$.

Following SPE14601 we correct formation testing pressures using a cosine function:

\[ \Delta O = \cos(\omega t + \phi_O) \]

$\phi_O$ is the time lag between sea floor and reservoir tidal fluctuations.
Why Correct Pressure Data For Tidal Effects?

Improves formation testing answers

• Reservoir Fluid Density Estimation
• Reduces Free Fluid Contact Uncertainty
• Improves Detection Of Reservoir Compartments

Some other benefits

• Improved well test and interference test planning
• Assessment of pore volume compressibility by the equation below

Tidal Efficiency \( R = \frac{\Delta P_{\text{reservoir}}}{\Delta P_{\text{seafloor}}} \), where both are due to ocean tide effects.

Then, it can be shown (eg SPE 103253) that \( R = \frac{C_{pp}}{(C_{pp} + C_{f})(1 + \nu)} \)

\( C_{pp} \) and \( C_{f} \): pore volume and fluid compressibilities respectively

\( \nu \) is Poisson’s ratio
Well X pressure data. A common gradient is proposed between the Upper and Lower sands.

Outstanding issues with the current straight line interpretation

1. Bias in residual errors from upper to lower Sands

2. Gradient inferred Oil density 0.15 g/cc. Lab PVT density 0.165 g/cc. The difference in density is significant. Which is correct?

Major consequences:

*Upper and Lower Sands may not communicate*

*Free water level for Lower Sand is has been incorrectly estimated (inaccurate prediction of OOIP)*
Well X Pressure Data

Pressure psi vs TVD

Excess Pressure psi

-1 psi

-0.5 psi

0 psi

Mobilities (all high)

FWL ZZZZm
TVDSS – previously accepted value
The Tidal History During The Well X MDT Job
Residual Errors (Excess Pressure) With No Tidal Correction

Pressure psi vs TVD

Excess Pressure psi
-1 1

Mobilities (all high)

Higher Tide

Mid Tide

Lower Tide

FWL ZZZZ m TVDSS

Tidal predictions

Saturday
0.24m @ 5:38 AM
2.14m @ 12:00 PM
0.60m @ 5:35 PM
2.38m @ 11:43 PM

Sunday
0.18m @ 6:14 AM
2.12m @ 12:36 PM
0.62m @ 6:05 PM
Apply A Correction Of 0.25 psi

Pressure Residual Errors Reduce.

- Apply a correction of 0.25 psi.
Apply a correction of 0.5 psi. Pressure residual errors reduce further, becoming unbiased.

**Pressure psi vs TVD**

- **Higher Tide**
- **Mid Tide**
- **Lower Tide**

**Excess Pressure psi**

-1 psi
-0.5 psi
0 psi

**Mobilities (all high)**

FWL: ZZZZ+2.5 m
TVDSS
FWL and $R^2$ vs Tidal Correction, TC

- $FWL$ and $R^2$ vs Tidal Correction
- $FWL$'s and $R^2$ (oil zone only) vs tidal correction

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The tidal correction applied should give a reasonable value for $C_{pp}$ (pore volume compressibility).

The properties of the Well X Oil and reservoir are

API ~ 20 deg, GOR 330 scf/stb, Tres ~ 58 deg C, Pres ~ 3100 psi.

Above properties suggest fluid compressibility $C_f$, to be about $3.1 \times 10^{-6}$ psi$^{-1}$ (depending upon the correlation used)

Equation for $R$ (Tidal Efficiency) then gives $C_{pp} \sim 4.5 \times 10^{-6}$ psi$^{-1}$. This is close to what was expected based upon data from other sources

<table>
<thead>
<tr>
<th>$C_f$ psi-1</th>
<th>$R$</th>
<th>Poisson $R$</th>
<th>$C_{pp}$ psi-1</th>
</tr>
</thead>
<tbody>
<tr>
<td>$3.10E-06$</td>
<td>$0.38181134$</td>
<td>$0.32$</td>
<td>$4.4623E-06$</td>
</tr>
</tbody>
</table>
Implications

Upper and Lower Sand could be in communication

At a Tidal Correction of between 0.5 and 0.6 psi, the residual errors from the straight line regression are unbiased between the Upper and Lower sands: based upon this result, there is no reason to assume that they are NOT in communication

Affects the understanding of the Free Water Level in the reservoir

The Free Water Level moves down by between 1.5m and 2.5m

Results in a significant increase in OOIP and UR

Both of these results are significant to the Field Development Plan

Note that the same conclusions were derived by regressing on both Upper and Lower sand points together, or just on Lower sand points
A Common Observation In Thin Gas Zones

Scenario

- Taking pressures in gas zones, beneath, yet close to Kv barriers
- Vertical well drilled with water based mud
- No Supercharging
- High mobility clean sands; Kv/Kx between 0.3 and 1
Typical Pressures In (Thin) Gas Zones

Note these points

Sample gas here

Kv Barrier

Kv Barrier

Kv Barrier

Dry Test

Lost Seal

Lost Seal

Gamma Ray (GR)

DD_MOB

Density (RHOZ)

Gamma-Ray (GR)

Thermal Neutron Porosity (TNP)

0.45

1.95

2.95

0.1

10000

gAPI
Add XS Pressures
What does the data suggest? 1

KV barrier exists at XX00m TVD ss

Points close to it have progressively lower excess pressures

• MCFL is the resistivity of the formation close to the formation tester probe

• It shows higher resistivity for these points (no deviation effects either; vertical well)

The data implies that filtrate has slumped downwards, away from the Kv barrier, and has been replaced by gas.

• Gas is much lighter than filtrate. Kv in the formation is high. Kv Barrier prevents replenishment of filtrate

There is significant saturation of mobile gas in the invaded zone

And this affected the measured pressure (next)
What does the data suggest? 2

PCow = Pgas – Pwater is significant

The FT measures filtrate (ie water) pressure

Hence Pmeasured = Pwater < Pformation = Pgas

Effect is observed beneath every KV barrier in the gas zone; most prominent beneath shallowest barriers

MCFL in the oil zone is much more uniformly low, and the “slumping effect” on pressure measurements is less prominent

Mobile gas has been implicated in incorrect gas interpretations elsewhere. For a review see Elshahawi et al, SPE 56712
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$PC_{ow} = P_{gas} - P_{water}$ is significant

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Hence $P_{measured} = P_{water} < P_{formation} = P_{gas}$

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Effect of A Thick, Spongy Mudcake

Pressure vs. Time Plot

- Overbalance ~ 260 psi
- 3rd pretest 55 cc
- 2nd 60 second slope - .41 psi/min (unacceptable)
- final 60 second slope 0.007 psi/min (good)
- 1st pretest 15 cc
- 2nd pretest 5 cc

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This is not normal supercharging since; pretest 1 pressure (70 sec) < pretest 2 pressure (70 sec)

Final pretest pressure is stable
The mud cake was spongy and contained much filtrate

This was expected because

• The overbalance was low (~ 260 psi).

The mud cake had probably been made thicker because

• The well had been suspended for some days due to a cyclone.

When the probe packer squeezed the mud cake, fluid was expelled into the formation, causing a “build down” over print on the “buildup” from small volume pretests

A large volume pretest (55 cc’s) was sufficient to completely remove this effect
How much fluid should be withdrawn from the formation?

And in what sequence?

Easy Answer is “It depends” upon the situation. Some basic guidelines below:

• Don’t withdraw too much fluid (assume no fluid sampling)
  • Only mobile filtrate should be in the volume of investigation of the test and only filtrate should enter the tool.

• Withdraw enough fluid to
  1) Break the mud cake
  2) Eliminate mud cake storage effects
  3) Understand Dynamic Supercharging DSC: multiple pretests help determine the existence of DSC. They can sometimes even eliminate DSC
The End

Thanks
Standard Error in Position of Fluid Contact

\[ \rho_1 = 0.277 \text{ gm/cc}, \rho_2 = 1 \text{ gm/cc}, \sigma_p = 0.3 \text{ psi}, \sigma_z = 1 \text{ ft}, \text{ simulations} = 10000 \]

1. **Standard Error in the Free Fluid Level**

\[ \bar{z}_1 = \frac{1}{n_1} \sum_{k=1}^{n_1} z_{k,1} \]

\[ \hat{z}_I = \frac{p_{o1} - p_{o2}}{\gamma_2 - \gamma_1} \]

\[ \sigma_{zI} = \frac{1}{|\gamma_2 - \gamma_1|} \sqrt{\sum_{\alpha=1,2} \left( \sigma_p^2 + \gamma_\alpha^2 \sigma_z^2 \right)} \left[ \frac{1}{n_\alpha} + \frac{(\hat{z}_I - \bar{z}_\alpha)^2}{H_\alpha^2} \right] \frac{12(n_\alpha - 1)}{n_\alpha(n_\alpha + 1)} \]

2. Graph showing standard error for different layer thicknesses and number of stations per layer.