Uncertainty versus Variability: Estimating the Petrophysical Ranges for Resource Assessment

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Objective of this paper

- Discuss and illustrate various ways of quantifying the expectation ranges of key petrophysical reservoir parameters in a structured and reproducible manner
- Differentiating between true uncertainty and mere variability
- Recognizing the possibility of biases in our subsurface data
The task: anticipating the range of likely subsurface outcomes on the basis of sparse data:

- Predicting the range in field-average reservoir properties to estimate a field’s HC resource
- Predicting the variability in reservoir properties that may be encountered when drilling new (development) wells

Some guiding principles:

- The confidence in a field’s mean properties and resource should increase with more data (uncertainty decreases)
- Drilling more wells increases the chance of sampling outliers (the more wells, the more subsurface variability is seen)
Appreciating scale differences

Petrophysical log:
- 2 - 3 ft investigation depth
- 1 ft along-hole resolution

Core plug:
- 1 * 2 inch

Borehole
6 - 24 inch wide

Seismic traces:
- 30-50 ft vertical resolution
- 25-50 ft trace spacing
(typical lateral resolution: 100 ft)

Reservoir model grid blocks:
- typically 300ft wide, 3 - 10 ft high

Reservoir fault block:
- typically several km wide, 10’s to 100s of ft high

Seismic Trace spacing
8 - 25x log investigation radius
= 300 - 600x core plug length

Reservoir grid-block width:
6 - 10 seismic traces
= 50 - 300x log investigation radius
= 1500 - 3000x core plug length

Reservoir grid-block thickness:
3 - 5x along-hole log resolution
= 40 - 120 x core plug width

The smaller the scale of sampling, the more variability is observed.
The uncertainty in a reservoir compartment’s Mean property is typically much smaller than the variability observed on a small scale (e.g., log or core).
Sampling statistics principle

To predict a field’s mean reservoir property values and a confidence level around it, we can treat the reservoir average computed for each well as a sample in a ‘Z-test’ approach:

**The principle of Z-test**

A sample’s Mean is expected to fall within a specified confidence band around the population MEAN as follows:

- \( \sigma \) (the standard deviation of the population)
- First calculate the standard error (SE) of the mean:
  \[
  SE = \frac{\sigma}{\sqrt{n}}
  \]
- The formula for calculating the z score for the Z-test is as follows:
  \[
  z = \frac{x - \mu}{SE}
  \]

where:
- \( x \) is a mean score to be standardized
- \( \mu \) is the mean of the population

Since the population Standard deviation is unknown, assume: \( \sigma = SD \)

As the number of samples (\( n = \) number of wells) increases, SD may remain stable or increase but
\[
SE = SD/\sqrt{n}
\]

should reduce

**Common issues and pitfalls:**

- Each well is a sample, not each datapoint in each well is a sample
  - *Reason being, we are estimating the reservoir average in the field, not the reservoir average in a well*
- If the number of wells drilled is very small, the approach becomes less reliable
  - *If \( n=1 \), \( SD = 0 \) hence \( SE=0; \) no uncertainty??*
- Biased sampling, for example where wells have been drilled on seismic sweet-spots
Porosity in a mature clastic reservoirs oil field

OBSERVATIONS:
• The spread in raw log data values doesn’t change much with drilling more wells
  • A measure of reservoir variability but NOT uncertainty around the field mean
• The confidence band (calculated using SE) around the field mean narrows with drilling more wells despite finding more outliers

ISSUES:
• How do we deal with the one well situation?
• Is 3 wells (end of appraisal stage) enough to confidently estimate the SE?
Now I have only one well drilled on the field. What values do I assume for the mean reservoir properties? And how do I estimate the uncertainty ranges around those assumed mean values?

**POSSIBLE METHODS:**

- Refer to analogues
- Treat zone-averages of stacked reservoir intervals as one population (to get more sample points)
- Break up the reservoir into meaningful subzones and compute the average properties for each of those (again, to get more sample points)
Possible workflow: Treating stacked reservoirs as one population

1. Calculate all reservoir-(sub)zone averages over the interval of interest
2. Make property histograms
   - Determine parameter correlations e.g., Porosity vs. depth, Porosity vs. Sw, depth-normalized porosity vs. Net-to-Gross
3. Determine the uncertainty bands around the parameter correlations (Standard Error of Y-estimate)
4. Tabulate parameter ranges per reservoir using the well observed values as the Mid and the ranges observed from the cross plots and/or histograms to yield Low/High
Possible workflow: breaking up a single reservoir into subzones

Example: deepwater turbidite well

Determine reservoir sub zonation based on OBMI interpretation

Average Value For Each Properties per Sand Cycle Zone

Water Leg

Calculated sums and averages for each subzone, and determine mean and std deviation for entire reservoir and HC zone only

Note: this method gives an idea of the possible spread in the reservoir averages but still, n = number of wells drilled and NOT the number of subzone samples

Use the statistic to as a reference to create mid, low and hi case for each property
Importance of Conceptual Geological Model

If the geological setting implies reservoirs that are relatively continuous, then our best assumption may be that the MEAN per reservoir is the mean of the well(s) in that reservoir.

However, in reservoirs that are highly variable laterally our best estimate of a reservoir zone MEAN may be the mean of the entire reservoirs stack.

**Bottom line:** ALWAYS interpret and use reservoir statistics in the context of conceptual geology.
The issue of Biased Sampling

Exploration high-grades prospects and drilling occurs on high amplitude

As a result, wells (RED) may be biased and a correction should be made before volume calcs

But often, this happens!
Petrophysical Uncertainty in a reservoir consists of two separate elements:

Uncertainty *away* from the well:
- Biased sampling
  - the field average may be different from the average seen in the wells

Uncertainty *at* the well
- Petrophysical parameter uncertainty
  - different assumptions on petrophysical evaluation input parameters, a different evaluation method / model (or a different petrophysicist ...) may yield a different evaluation result for the same well
- Not to be confused with the core-to-log calibration confidence
  - these are two different things

In green fields with sparse well data, uncertainty away from wells would be dominant, whilst ...

In brown fields with dense well control and/or in fields with complex / challenging lithology, log-evaluation uncertainty can a significant contributor to total HCIIP uncertainty
Scatter observed in the core-to-log calibration is more indicative of the small (core-plug) scale heterogeneity of the rock than it is of log-evaluation uncertainty. Other issues like core depth matching, stress loading and sampling bias also play a role.
Tie between log and core reasonable given reservoir type and data quality/quantity?

Yes = accept log evaluation

No

Suggested Workflow for assessing PP evaluation Uncertainty

Computed logs (NTG, Porosity, SW)

Check core-to-log calibration

Example: Porosity

Establish uncertainty ranges for petrophysical model parameters

Assess sensitivity of evaluation results to parameter uncertainty

Monte-Carlo simulation to assess the aggregate effect on HCPV

Re-visit log evaluation

Consider alternative evaluation methods

Tool accuracy considering logging conditions

Observed spread in RCA grain density

Reflective of mud type and reservoir fluid / logging conditions
Parameter Uncertainty in Mapping and 3D Modeling

• Principles of Geostatistical Gridding
• Data Representativeness
  – well sampled Property versus population (=field) Mean
• Depth and Spatial Trends
Geo-statistical gridding - kriging and related algorithms

Kriging solution

Stochastic simulation conditioned to the kriged solution

Distribution model

Assumed population Mean, StDev

Spatial de-trending (depth and/or lateral trends)

Normalization (normal score and/or other transforms)

Back transformation

Variogram model (controls data weighing)

Kriging “engine”

Stochastic simulation conditioned to the kriged solution
Distibution Uncertainty - Statigraphic zone / facies bias

- Property sampling per stratigraphic zone is typically limited
- How do we know the data is representative?

Depth-normalized porosity – all zones

Regional Por-Z model

Porosity histogram
Zone A

Zone B

Zone C
Regional property trends are often present and broadly recognized but the trend uncertainty is not.

Example is from an unconventional play with areas of dense well data and area with sparse wells.

Recommended workflow:
1. De-cluster the data
2. Establish the range of trend models that could fit the data
3. Perform uncertainty runs simulating uncertainty in the trend model on top of local variability (seed)
Risk of mis-interpreting trends e.g., due to impact of cut-offs

- Use of Porosity cut-off may cause underestimation of porosity decline with depth.

- Use of porosity cut-off may introduce a trend of decreasing net-to-gross towards downflank.

Well logs PHIT w/o cutoff, colored by reservoir flag

Red = Zone avg with Por cut-off
Blue = Zone avg without Por cutoff

Porosity

TVDss

Well A
Well A shifted 500 ft downdip

N2G: 0.83
PHI: 0.127

N2G: 0.82
PHI: 0.134

N2G: 0.31
PHI: 0.137

N2G: 0.60
PHI: 0.121

N2G: 0.65
PHI: 0.128

N2G: 0.23
PHI: 0.132
Reservoir Parameter Uncertainty
- Quantifying the impact
Reservoir Parameter Uncertainty – holistic view

Petrophysical Evaluation Uncertainty

- Localised errors (individual zones/wells)
- Systematic errors (affecting all wells)

Population Mean Uncertainty (= sampling bias)

- Use Z-test principle to simulate sampling bias

Distribution Uncertainty

- Local distribution pattern
- Field-wide trends

Quantify, simulate as a stochastically sampled bulkshift

Quantify, use as variogram nugget

Random seed in stochastic simulation

Consider alternative trend models

\[ \sigma \text{ (the standard deviation of the population)} \]

First calculate the standard error (SE) of the mean:

\[ SE = \frac{\sigma}{\sqrt{n}} \]
Summary of Key Messages

- Use concept of sampling statistics but with care
  - Discriminate between uncertainty and variability
  - Importance of scale vis-à-vis the entity we try to estimate (a well is a sample of a reservoir MEAN, a log datapoint is not)
  - Consider treating multi-stacked reservoirs as one population
  - Recognize and mitigate biases in our dataset
  - ALWAYS refer back to a conceptual geological model

- Understand the strengths and limitations of stochastic simulation
  - Consider de-clustering techniques where wells spacing is clustered
  - Look for subsurface trends but also identify and quantify the uncertainty around those
  - Recognize the limited size of per-reservoir sampling and hence the confidence in sample distributions
  - Recognize what a random seed iteration can and cannot address