AGENDA

• Estimating EUR & Type Curve Development
  • Understanding Your Reservoir
  • Production Analysis & Understanding Performance
  • Useful Tools
  • Using Analogy & Data Analytics
  • Big Data Applications, Important Things to Consider
    – Field Applications & Live Examples
    – Important Takeaways & Other Considerations
WHAT SMART PEOPLE SAY ABOUT UNCERTAINTY

• “We must become more comfortable with probability and uncertainty.”
  – Nate Silver (author and statistician, FiveThirtyEight.com)

• “Some people say, ‘How can you live without knowing?’ I do not know what they mean. I always live without knowing. That is easy. How you get to know is what I want to know.”
  – Richard Feynman (Nobel prize-winning physicist)

• “The world is noisy and messy. You need to deal with the noise and uncertainty.”
  – Daphne Koller (AI researcher, Stanford University)

• “Recognizing uncertainty is a sign of humility, and humility is just the ability or the willingness to learn.”
  – Charlie Sheen (Two and a Half Men)
Prices

Production & EUR

Capital Costs

Operating Costs

Royalties

Components of a Half-Cycle Economic Analysis

- Market prices are hard to predict
- Normally predictable to ±70% with 95% confidence one year out
- Hedging can improve certainty

- Well performance
- Operational issues
- Economic factors can limit

- Usually predictable within 15%
- Uncertainty largely tied to success/failure and experimentation

- Transportation bottlenecks
- Line pressures
- Unexpected issues, maintenance
- Competition, partnerships

- Long term uncertainty in regulatory framework
- Short term is usually quite certain
STATISTICAL AGGREGATION

• It has long been recognized that adding up high confidence estimates (e.g., well by well reserves) results in extremely high confidence aggregate estimates (e.g., company reserves).
  – Put another way - Adding a bunch of low estimates results in a too low estimate
  – Similarly (but less of an issue as generally companies do not disclose high estimates) – adding all high estimates is too aggressive

• Statistical techniques to account for this affect are growing in popularity

• Why would you aggregate?
  – Potentially higher Proved reserves
  – Alternate method to historical SEC step-out limitations
  – Potential for more rigorous treatment of P10 and P90 reserves definitions
  – It’s new(ish) and fancy! Guidelines first published by SPEE in 2010: SPEE Monograph 3.
The “Trumpet Plot” shows the convergence to the mean with a higher number of wells/locations drilled.

Fig. 4.14 – Probability versus Well Count
STATISTICAL AGGREGATION

- Who is interested in aggregation
  - Parties who care mostly about P90 or Proved reserves: US clients and international clients familiar with US disclosure
  - Technical experts frustrated with a lack of statistical rigor in the oil patch

- The current governing guideline is SPEE Monograph 3 which requires
  - “Wells exhibit a repeatable statistical distribution of estimated ultimate recoveries”
  - “Offset well performance is not a reliable predictor of undeveloped location performance”
  - “A continuous hydrocarbon system exists that is regional in extent”
  - “Free hydrocarbons (non-sorbed) are not held in place by hydrodynamics”
  - All statistical methods presented in the Monograph assume observations are independent and follow normal or log-normal distributions.
EXAMPLE OF REPEATABLE STATISTICAL DISTRIBUTION

The distribution shows a consistent mean and variance.

This is for a single formation in a defined area.
EXAMPLE OF REPEATABLE STATISTICAL DISTRIBUTION

Distributions may be consistent within a given area of a play while not being consistent across the play.

Can be locally homoscedastic and globally heteroscedastic.
Monograph 3 advocates the concept of anchor wells and concentric radii. Statistics must be consistent between radii and around every anchor well.
• If all requirements are met, doing aggregation the Monograph 3 way is very easy.
  1. Calculate the ratio between your P10 and P90 EUR estimates
  2. Tally up your number of locations
  3. Look up the factor you need to multiply your P50 EUR estimate by in order to get your P90 EUR.

• Unfortunately, Monograph 3 doesn’t provide detailed guidance on
  – How to calculate EUR
  – How to calculate the number of locations
  – or what to do if estimates of P10 and P90 are uncertain.
PROBLEMS WITH STATISTICAL AGGREGATION

• Most oil and gas fields show non-homoscedastastic behavior

• Both the mean and variance are non-stationary. This can be in terms of exploitation methods, stratigraphic horizon, time and position

• There are non-trivial correlations between wells: expected performance is almost always a function of distance, spacing and the evaluators' assumptions.

  COGEH states “The evaluator should also be aware that reserves estimates for some wells may be dependent on each other; i.e., if the estimate is incorrect for one well, it is equally incorrect for the others.”

• This doesn’t preclude the use of aggregation, but the analysis must be more sophisticated than the simple examples presented in Monograph 3
WHY WOULD YOU CHOOSE NOT TO STATISTICALLY AGGREGATE?

- There is no need if all you and your investors care about is P50 (2P).

- Field data may be insufficient or contradicts the requirements of Monograph 3:
  - The statistical distribution of estimated ultimate recoveries may be inconsistent: well results may change with completion technique.
  - Offset well performance may be a reliable predictor of undeveloped location performance: most fields show that offset wells do statistically influence expectations of the mean… put more simply: “reservoirs have sweet spots”.
  - The hydrocarbon system may change over the region of interest: as with CGR in the Montney and Duvernay.
  - Field data is sufficient and fits requirements of Monograph 3, or can be manipulated to do so, but the observations indicate dependence between variables or other statistical behaviors that don’t fit the examples in the Monograph and you are unable or unwilling to implement alternate statistical algorithms.

- You would rather disclose Proved reserves with a confidence greater than 90% under current rules, remembering that reserve guidelines generally say “greater or equal” in reference to high confidence or Proved estimates.

- The imposition of the SEC’s five year rule may negate any increase in proved reserves booked.

- Other risk factors may be more important, like geopolitical risk or corporate governance.
"SWEET SPOT" EXAMPLES
HORSESHOE CANYON EUR
“SWEET SPOT” EXAMPLES
MILK RIVER/MEDICINE HAT EUR
“SWEET SPOT” EXAMPLES
CARDIUM OIL EUR
• Why are single type curves so popular?
  – Quick & Simple
  – Financial analysis/metrics (play versus play or region versus region)
  – Marketing
    • “Our 7 BCF Type Curve…” is a lot easier to digest than “Our type curves for the region vary between 4 and 10 BCF recoverable per well”

BUT…In practice, single type curves are rarely sufficient for predicting future results.
ONE IS (ALMOST) NEVER ENOUGH

- If well results have very large variance how could one curve capture enough character?
- Even a Low/Best/High can be insufficient if the asset is large enough

- Dividing that data by reservoir character, CGR, Normalized Peak Rate etc. can tell us a lot more
- Type Curves on groups can have overlap – it’s unlikely that variations have hard borders.
What is a Type Curve?

- It is a description of the production behavior we have seen/observed to date.

- Should it be considered a representative EUR that we use?.....Maybe if developed properly.
SO WHAT’S MY NUMBER?

\[ \text{# of Type Curves} \sim f \left( \text{Geographical/Geological regions} \times \text{Fluid Types} \times \text{Well Vintage} \times \text{Completions} \times \ldots \right) \]

How many type curves do I need?
Important considerations when developing type curves:

- Operator (operating conditions)
- Geographic variation (geology)
- Learning curve over time
- Well length and/or # of laterals
- Completions (# of stages, tonnes/frac, frac spacing, fluid, completion type, …)
- Cardinality (drill order)

- ……and more!
KAYBOB DUVERNAY EXAMPLE
The Duvernay is a Thermogenetic shale
  - Higher temperature reached by source rock the more hydrocarbon cracking, higher gas content and lower liquid yields

Development started in 2010 and reached ~250-300* mmcf/d as of December 31, 2016
NORMALIZATION – COMPLETION TRENDS

DUVERNAY SHALE - COMPLETION TRENDS

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NOT THAT ANYONE WOULD DO THIS...RIGHT?

- Probit distribution of gas EUR per 200T placed for ALL duvernay
- Suggests P50~100 mmcf/200T stage
- But is this really a reasonable representation of the Duvernay?
Logic would dictate that more mature regions (lower liquids) would produce higher gas rates because of:

- Fluid mobility
- Higher TOC based porosity
- Higher pressure gradients
GAS RATE PER TONNE PLACED
DIVIDING THE RESULTS BASED ON CGR
• Best Estimate EUR could vary from 20 to 400 mmcf per 200T!
• Interpretations with corresponding liquid production has obvious NPV implications
IMPORTANT TO CONSIDER OTHER COMPLETION CHARACTERISTICS
IMPORTANT TO CONSIDER OTHER COMPLETION CHARACTERISTICS
TAKEN FLUIDS INTO ACCOUNT – WHAT ABOUT THE ROCK?

• If the data is grouped appropriately we can start to see reservoir characteristics if all completions are comparable…
  – Of if completions are highly varied you might see that too
REPEATED RESULTS ABOVE/BELOW P50...

High concentration of results above P50...Best Estimate Typecurve for this area may be significantly higher than P50 for whole of Kaybob.
TYPE CURVE EXAMPLE

Data presented by DLS TWP
TYPE CURVE EXAMPLE

Data presented by UWI
A QUICK ASIDE ON ‘CARDINALITY’

Cardinality (i.e. drill order)
- Should we expect the same results with additional drilling? Does the old type curve still apply?

Comparison between 2 Plays:
- Milk River vs Montney

This is of particular importance in the ‘more conventional’ Spirit River, where higher permeability and downspacing can lead to diminishing returns not yet observed (particularly in late life)
MONTNEY CARDINALOGY PER STAGE

Montney Gas Type Curve Cardinality (First 48 Months Rate vs Cumulative)

Data provided by IHS Data Hub - May 30, 2014, 11:32 PM. USA/Eastern
DEVELOPING WELL EXPECTATIONS

• You need to understand your reservoir!

• Fundamentally, you need an underlying knowledge of:
  – Geology: Petrophysics (Phi, Sw, Sor etc.)
  – Reservoir Fluid & Flow Dynamics (governing performance data)
  – 3Ps: PVT, Pressure and Permeability

• Performance Differences:
  – It’s not just completions….try to separate reservoir from completions (if you can, and you can’t always do this).
  – Small Changes in reservoir properties can make a big difference in production!
COMMON PITFALLS

ACTIVITY!
WELLS 1-4

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WELL 5 WAS THE AVERAGE?!?
COMMON PITFALLS – AVERAGES

• Common ‘malpractice’ is to complete decline analysis on the average well performance.
• Wells with atypical well production profiles can have dramatic effects on average well profile
IMPORTANT POINTS TO CONSIDER: PRESSURE INFLUENCES

- Additional back pressure/drawdown can behavior changes that cannot be quantified when evaluating based on rates alone.
- This can also appear as a different flow regime prior to linear flow in early time data.
- Often when estimating reserves by decline alone, the back pressure causes a flattening of behavior.
- Conversely, increasing drawdown cause an artificial inflation of rates, can falsely appears as better productivity.
- Can lead to over/under estimation of reserves/EUR.
- Need to recognize “false” reservoir energy.
MEAN CURVES ARE CONDENSED DATA

Outlier data. Most of our data behaves nicely except these areas. Revise group to get a new mean curve.

- Always review the underlying data set.
- Move between a mean representation and examine outlier data.
UNDERLYING DATA: UNDERSTAND
WHAT IS IN YOUR MEAN CURVE

Outliers and their influence.
How much impact do they have on the mean?
Does the mean adequately describe the data?

When should I stop?
COMMON PITFALLS – SURVIVOR BIAS

- Strongest wells produce at higher rates for longer
  - Are you surprised?
- The poor outliers can disappear prematurely from the data set if shut-in for economic reasons
  - Poor wells drop out – that helps my average!
- If the highest rate wells produce at higher rates longer what does that do to our “average” well profile?
Decreasing well count has a significant impact on the curvature of this mean curve.

Note the well count. Can mislead your type curves!
ADJUSTING FOR SURVIVOR BIAS

Plot is now adjusted for declining well count. Do we need to adjust further?
COMMON PITFALLS – LATE LIFE ASSUMPTIONS

- Transient Flow Behaviour
  - Appears as a period of shallow decline on log(q) vs log(t) plot
  - Appears as a slope less than -1 on log(q) vs log(tMB) plot
  - DCA in this flow period is theoretically justified, but only for the duration of transient flow, and can have an Arps exponent between 0 and 2.
  - Have we actually observed this behavior?
    - Of course… it is currently the dominate flow regime for most wells in shale gas resource plays (eg Marcellus, Eagleford, Montney, Horn River)

- Very easy to over estimate late life behaviour with very shallow declines beyond type curve history
Very few wells show indication of Boundary Dominated Flow
Even looking by year averages only wells from 2010 and older show any indication (<5% of data set)
SO, NO BDF PERIOD EVIDENT YET?

- If reservoir is unconventional there may only be a few examples of BDF
- What do we use?
  - Often, wells in these reservoirs produce majority of their hydrocarbons within the first 3-4 years and have paid out over this time. You could restrict your forecast to this time period and not worry about EUR.
  - You could estimate permeability from the few wells that entered BDF and use models to predict long term behavior for a typical well still in transient flow
  - Long term producing vertical wells can give us some clues and rough estimates of what to do… they may be in radial flow which would allow us to estimate perm
  - You could assume a long-term final decline based on what has been observed to date, at least until the time to BDF becomes clear.
LATE LIFE ASSUMPTIONS

- By default, for late life assumptions on horizontal wells we look to longer history Vertical Wells
- Plot shows decline rate for Deep Basin Verticals in Kakwa
- Spacing of 80-160 acres for verticals is one thing...what about a frac stage every 100 meters?
  - 10-20 acres / stage
RESERVES & RESOURCE EVALUATION PROCESS

Estimated PIIP
- Assumed petrophysics cutoffs
- Kerogen density assumptions

Undeveloped Reserve/Resource Assignments
- Assign reserves and resources offsetting performance using volumetrics and analogy

Performance Data
- Initial Rate assumption
- Typecurves (Arps eqn)
- Terminal Declines

Recovery Factors
- Check performance / decline analysis versus PIIP estimates
- Do these make sense based on produced fluid encountered?
Cores used:
100/01-28-048-18W5/00
100/05-17-049-18W5/00
100/01-05-049-19W5/00
102/12-04-050-18W5/00
100/16-03-051-18W5/00
100/13-11-058-27W5/00
100/01-17-059-01W6/00
100/01-34-059-02W6/00
100/03-10-060-02W6/00
100/13-02-060-02W6/00
100/01-07-063-05W6/00
100/08-02-062-06W6/00
100/08-07-062-06W6/00
100/10-29-063-07W6/00
100/06-08-064-07W6/00
100/10-28-063-07W6/00
100/09-03-062-05W6/00
RECALL:
Distributions may be consistent within a given area of a play while not being consistent across the play.

Can be locally homoscedastic and globally heteroscedastic.
The shape of this curve looks pretty familiar...so one type curve should suffice.
SPLITTING UP WELL RESULTS

- Performance from the Spirit River is guided more by OGIP than other “resource plays”
- Since core areas tend to be drilled up first can we take historical development and apply the same type curve moving out of the fairway?
Similar to Duvernay – these wells are grouped by first 6 month cumulative production.
SWEET SPOTS EMERGE
If development is moving to the “fringes” the appropriate type curve should be used to guide expectations.
P75-P50 GROUP

Gas Type Curve (Rate vs Time)

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MAJOR CONCLUSIONS

• There will be significant pressure from financial markets and management to simplify the analysis. This has the dangers of condensing varied reservoir performance (multiple type curves) into a single “representative” type curve.
• Many current plays are still in infinite acting flow and so it is difficult to verify DPIIP assumptions from production data.
• Good areas are developed first and will be drilled until there is enough interference, hopefully not too much!
• Typical long term decline rates may be steeper than you expect: median decline rates for gas wells after 30 years of production are approximately 5-10%. A minority of wells have much shallower declines.
• Know your reservoir before you start down type curves...what is the most important variable that effects performance?
  – Fluid, Phi-h, Facies?
• Many important parameters, such as EUR and decline rates, can be neither normally nor log-normally distributed.
THANK YOU!

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