Chances Are. . .
We Don’t Know How Things Will Turn Out

Michael Morgan

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Let’s Talk About Three Types of Risk

- **Reservoir Risk** – Much of what governs a well’s performance happens hundreds if not thousands of metres below the surface.

- **Market Risk** – Producers have little control over the prices they charge for their product, and those prices are volatile.

- **Operational Risk** – Producers do have control over their operations and, significantly, can often choose how flexible their development plans are.
Let’s Talk About How to Represent These Risks

- Stochastic reservoir modeling can allow better quantification of reservoir risk.
- Stochastic price modeling will allow representations of prices and the relationship between prices.
- Real option analysis can provide estimates of the value of operational and investment flexibility.
Reservoir Risk is Mostly What We Are Asked to Model

- Most geologists and engineers have been exposed to Monte-Carlo OGIP and OOIP calculations.
- The emphasis on resource plays and contingent resource evaluation has exposed many more to multi-well statistics.
- There is an emerging ability to model single-well uncertainty.
Figure 1: Upper Montney Initial Production (per frac)

Test Rate (Mcf/d)

Rig Release After
- Oct 1987
- Jun 2006
- Jul 2007
- Jul 2008
- Dec 2008
- Aug 2009

Cumulative Probability

P90 = 280
P50 = 690
P10 = 1,720
P90 = 180
P50 = 410
P10 = 960

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Figure 2: Production – Horizontal Well A

<table>
<thead>
<tr>
<th>Date</th>
<th>Rate (Mcf/d) Calculated $P_{wf}$ (psia)</th>
</tr>
</thead>
<tbody>
<tr>
<td>2007</td>
<td></td>
</tr>
<tr>
<td>2008</td>
<td></td>
</tr>
<tr>
<td>2009</td>
<td></td>
</tr>
<tr>
<td>2010</td>
<td></td>
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</tbody>
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Figure 3: Exponential Decline – Horizontal Well A

\[ D_i = 19.7\% \]
Figure 4: Harmonic Decline – Horizontal Well A

\[ D_i = 40.8\% \]
Figure 5: Flowing Material Balance – Horizontal Well A

Minimum OGIP = 3,950 MMcf
Minimum A = 75 acres
\(r_e \geq 1,022 \text{ ft}\)
\(kh \leq 6.3765 \text{ mD ft}\)
\(k \leq 0.0486 \text{ mD}\)

NB: \(kh\) and \(k\) are not adjusted for frac count.
Figure 6: Linear Flow Analysis – Horizontal Well A

\[ \sqrt{k h_x} = 10,169 \text{ft}^2 \sqrt{mD} \]
\[ x_f = 493 \text{ ft} \]
Figure 7: Pressure Dependent Permeability
Figure 8: Example Horizontal Well Forecast

Decline Analysis Summary @ 2011/09/01

<table>
<thead>
<tr>
<th>Reserves Classification</th>
<th>Raw Gas (MMcf)</th>
<th>Rates (Mcf/d)</th>
<th>Decline</th>
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</thead>
<tbody>
<tr>
<td></td>
<td>Ultimate Cum Prd</td>
<td>Remain</td>
<td>Initial</td>
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<tr>
<td>Pv Prd</td>
<td>6300</td>
<td>2749</td>
<td>3551</td>
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<tr>
<td>P + P Prd</td>
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<td>2749</td>
<td>4451</td>
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<tr>
<td>PPP Prd</td>
<td>8600</td>
<td>2749</td>
<td>5851</td>
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<tr>
<td>Minimum ...</td>
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<td>2749</td>
<td>1751</td>
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<tr>
<td>Maximum ...</td>
<td>16000</td>
<td>2749</td>
<td>13251</td>
</tr>
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</table>

Average Production Rates (Last 12 months ending 2011/08/31)

|                       |              |              |              |
|                       | Gas : 980.8 Mcf/d | 975.1 Mcf/cd | WGR : 2.2 bbl/MMcf |
| Oil : 0.0 bbl/d       | 0.0 bbl/cd   | GOR : 0.0 scf/bbl |
| WC : 100.0 %         |              |              |              |

Cumulative Production

| Oil : 0.0 Mbbl | Gas : 2749.4 MMcf | Water : 11.8 Mbbl |
Quantifying Single Well Uncertainty

- The advent of approximate algebraic expressions for linear flow, elliptical flow, and modified Arps declines has given great flexibility in well forecasting without the computational cost of simulation.

- Recent papers on Bayesian updating show how these simple models can be used to automatically calculate P10, P50 and P90 estimates for a single well. With these methods you guess a range of input parameters (like initial rates, declines, exponents, etc) and then refine that range as you get more and more data.

- You still need to pick the right model and the fit is only as good as the data, so we view these methods as supporting, not replacing, an evaluator’s judgment.
The Next Most Common Risk We Model is Price Risk

- How Variable Are Prices?
- Let’s look at price uncertainty two ways
- There is volatility of the price of a specific hydrocarbon
- There is volatility between prices
Figure 9: WTI Historical and Futures Prices

Date
$/bbl
2000 2010 2020
20 40 60 80 100 120
20 40 60 80 100 120

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Figure 10: HH Historical and Futures Prices
Futures curves aren’t necessarily good predictions of future price.

Is there a way to calculate price uncertainty?

Yes! We can look at options prices and back-calculate the *implied* volatility for these futures prices.

For oil, this looks like...
Figure 12: WTI Historical and Futures Prices with Uncertainty
Figure 13: HH Historical and Futures Prices with Uncertainty
Figure 14: Propane Historical Prices with Modeled Uncertainty
How are Prices Related?

- Much as we’d like prices relationships to be stable, they are not.
- For example, we’ve seen a decoupling of WTI and Brent prices.
- Even when the relationships are stable, they don’t follow nice distributions.
- There are statistical measures of this (eg ADF and Jarque-Bera tests), but a picture is probably better. For simplicity, let’s look just at price offsets...
Figure 15: Are Liquid Price Offsets Stationary to WTI?
Figure 16: Are Liquid Price Offsets Normally Distributed?

Edm. Light
NOT NORMAL

Propane
NOT NORMAL

Butane
NOT NORMAL

Brent
NOT NORMAL

Cromer. Light
NOT NORMAL

Cond
NOT NORMAL

Basis (C$/bbl)

Probability

NOT NORMAL

NOT NORMAL

NOT NORMAL

NOT NORMAL

NOT NORMAL

NOT NORMAL

Basis (C$/bbl)
What About Operational Flexibility?

- One method of quantifying the impact of operational flexibility is “Real Options” analysis.
- This analysis captures the inherent flexibility of development. Companies can always wait to gather more data, accelerate development when prices are favorable and halt development when times are bad.
- The more flexible the project, the more price volatility can be managed, *without financial instruments.*
What About Operational Flexibility?

- Our first analysis considered the value of exercising a put option within an unconventional JV. The put option gave the seller the opportunity to divest the remaining WI at a fixed price (the strike price). The analysis found that the risk-neutral NPV was more valuable than the strike price ($100 vs $80 million). In the absence of capital constraints, it would not be a good idea to exercise the option.

- However, the seller was under capital constraints. Exercising the option allowed the seller to repay debt and gain flexibility in financing other projects. A further analysis could quantify if these benefits outweighed the $20 million “cost” of exercising the option.
The investment community has lots of tools to rank risky investments and build portfolios (like Sharpe Ratios and Markowitz Efficient Frontiers)…

…but they need expected returns, expected volatilities and expected correlations.

The reserves community has built a language for modeling well performance risk using different reserves categories and classes…

…but we haven’t applied the tools the investment community has built.
Monte-Carlo OOIP, OGIP and type-curve work is standard practice.

Price forecasting is updated quarterly and price sensitivity runs are standard practice.

We have tools to quickly build property definitions. For example, we can replace all elements in a resource evaluation in about 10 minutes. This isn’t as fast most spreadsheets, but our well and royalty models are more sophisticated.

We have daily updates of market volatility estimates and are using this to refine our reference price volatility modeling (to be published at this autumn’s SPE conference).
What’s Coming

- Further analysis of volatility between hydrocarbon prices.
- Real options analysis of gas-plant construction (to be published at this autumn’s SPE conference).
- Monte-Carlo simulation of field economics using our price volatility models.
- VaR (Value at Risk) calculations based on detailed well-level economics.
- RaR (Reserves at Risk) calculations of resources both economic and uneconomic.

*In short, we are working to provide estimates of the intrinsic volatility of projects, in addition to their expected value.*
There’s no way around it, oil and gas investments are risky.

There are lots of tools to deal with modeling different types of reservoirs and plays. It may take a while, but once we have a good reservoir description we can choose the right tools and make good production forecasts.

Prices are much harder to model.

You can sell your production forward or buy puts, but, to my mind at least, you can never *insure* your way to profitability.

The best you can do is invest in projects that are expected to make money most of the time and offer lots of “outs”.

Everyone is looking for these, good luck.