Overview of SPEE Monograph 4

SPE Reservoir Engineering and Production Optimization
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Overview

» Monograph 4 - Estimating Ultimate Recovery of Developed Wells in Low Permeability Reservoirs

» Purpose – assess current methods to forecast performance of wells in unconventional reservoirs given different reservoir types, different completions, and different well maturities

» For sale from the SPEE web site – Society of Petroleum Evaluation Engineers - secure.spee.org

» Mainly developed in the United States but applicable to Canada

» Provides substantial insight and workflow suggestions. Does not provide prescriptive requirements that have been legislated.
Monograph 3 provides reasonable guidelines to estimate undeveloped reserves and resources in resource plays:

» Determine if you have a resource play
» Identify proper analogs wells (similar characteristics)
» Use log normal distributions of your EURs
» Determine proved area from the distribution model
» Adjust deterministic EURs to statistical EURs

» Given that we now have substantial production data from unconventional plays, Monograph 4 was written in order to provide guidance in regards to producing reserves
What is a Resource Play?

» Repeatable EUR expectations
» Continuous hydrocarbon system
» Hydrocarbons are not held in place by hydrodynamics
» Usually requires stimulation and is in a low permeability environment
Topics Covered

» Understanding tight reservoirs
» Reservoir characterization
» Drilling, completions and operations
» Conventional decline analysis in unconventional wells
» Fluid flow and alternative decline methods
» Model based well performance analysis and forecasting
» Application of numerical methods quantifying uncertainty in the estimation of developed reserves
» Examples
1) Geological Characterization

» Provides overview of major plays
» Discusses different data sources in order to properly understand your reservoir such as:
  » Regional geology, structure geology, stratigraphy, lithofacies types, depositional system, diagenesis, organic geochemistry, hydrogeology, natural fractures, etc.
» Quantifying fluid characteristics and how these change with time
» Identifying the “sweet spots”
2) Drilling, Completions and Operations

» Discusses progression of wells (longer, more proppant/stages)

» Other factors to consider that would be understood well by a company’s drilling and completions group

» In regards to operations, drawdown a major topic. Does not recommend using average pressure data when conducting simulation studies

» Understanding interference
3) Decline Curve Analysis

- Explains concepts, discusses best practices and when each is applicable

<table>
<thead>
<tr>
<th>Decline Model</th>
<th>Major Strength</th>
<th>Major Limitation</th>
</tr>
</thead>
<tbody>
<tr>
<td>Arps (original)</td>
<td>Easy to use, couple with economics software</td>
<td>Requires BDF, constant BHP</td>
</tr>
<tr>
<td>Arps (modified)</td>
<td>Easy to use, couple with economics software, valid in BDF</td>
<td>Early BDF, late exponential decline required</td>
</tr>
<tr>
<td>Stretched exponential</td>
<td>Transient flow model</td>
<td>Not accurate in BDF, tends to be conservative in most cases</td>
</tr>
<tr>
<td>Linear flow</td>
<td>Correct physics for many fractured wells</td>
<td>Inappropriate for BDF, optimistic</td>
</tr>
<tr>
<td>Duong</td>
<td>Correct physics for many fractured wells (essentially linear flow)</td>
<td>Inappropriate for BDF, optimistic</td>
</tr>
<tr>
<td>Duong (modified)</td>
<td>Correct physics during transient and BDF</td>
<td>Not available in commercial software</td>
</tr>
</tbody>
</table>
Fluid Flow Theory

» Not prescriptive about circumstances to use each, however, adequate empirical match required. Situations to use discussed.

<table>
<thead>
<tr>
<th></th>
<th>Arps (orig.)</th>
<th>Arps (mod.)</th>
<th>Stretched exponential</th>
<th>Linear flow</th>
<th>Duong (orig.)</th>
<th>Duong (mod.)</th>
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</thead>
<tbody>
<tr>
<td>Reasonable forecasts for low permeability reservoirs?</td>
<td>no</td>
<td>maybe</td>
<td>maybe</td>
<td>maybe</td>
<td>maybe</td>
<td>yes</td>
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<tr>
<td>Valid for transient flow?</td>
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<td>no</td>
<td>yes</td>
<td>yes</td>
<td>yes</td>
<td>yes</td>
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<tr>
<td>Valid for BDF?</td>
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<td>yes</td>
<td>no</td>
<td>no</td>
<td>no</td>
<td>yes</td>
</tr>
<tr>
<td>Need to change parameters with longer history?</td>
<td>yes</td>
<td>yes</td>
<td>yes</td>
<td>yes</td>
<td>yes</td>
<td>yes</td>
</tr>
<tr>
<td>Good with limited data (&lt; 1 year)?</td>
<td>no</td>
<td>no</td>
<td>no</td>
<td>maybe</td>
<td>yes</td>
<td>yes</td>
</tr>
<tr>
<td>Easy to use, combine with economics software</td>
<td>yes</td>
<td>yes</td>
<td>somewhat</td>
<td>no</td>
<td>no</td>
<td>no</td>
</tr>
</tbody>
</table>
Decline Best Practices

» Declines should be completed on the well level – not groups of similar wells

» All phases should be plotted and pressures. Daily production data is a useful tool

» Complex diagnostics plots can quickly identify well transition from transient behavior to pseudosteady state or interference

» No “b” values higher than 2 under most circumstances

» Limited period of time of high “b” values (months)

» Multiple segments to model performance changing events

» Terminal decline rate required under most circumstances
Terminal Decline Rate

» Enforcing a terminal decline rate in late time is mandatory for wells with high hyperbolic rates.

» The terminal decline rate at which to flip to exponential decline should be estimated based on demonstrated performance and or imposed by volumetrics.

Terminal Decline = 10%
Producing Life = 27 yrs
EUR = 10.2Bcf

No Terminal Decline, Final Decline = 0.95%
Producing Life = 92 yrs
EUR = 14.8Bcf
Dynamic “b” Factor

- It is well understood that modern day horizontal wells in tight reservoir do not follow basic Arp’s equations where the hyperbolic exponent “b” is normally considered constant.
- This is because early flow periods are in a transient phase and are not yet under boundary dominated flow.
- A typical b profile is shown below where early time flow is highly hyperbolic followed by a long relatively stable b period ultimately leading to exponential flow (b=0) in late life.
Because of this, there has been ongoing research and development of alternative forecasting methods including Duong, Power Law, etc. which do not rely on Arp’s but have yet to gain broad acceptance.

We recommend approximating this behavior using a three stage Arp’s function with a terminal exponential decline rate.
What Value of b should I use?

- Use Duong formula to fit early time data.
- Calculate instantaneous “b” factor and decline rate.
- Create a multi-segment Arps forecast to approximate the transient nature of “b” with discrete segments.
When working with large datasets, it is important to recognize that there are a number of variables or “attributes” of a well that will cause performance to differ from other wells including:

- Vintage
- Operator
- Length
- Reservoir Quality
- Cardinality (1st vs. 6th Well)
- Geographic location
- Fluid Type & Volume
- Proppant Type & Tonnage
- # of Stages
- Open vs. Cased
- IP rates
- Etc.

It is very important that when assessing type curves and ultimately future performance expectations for an area, that these types of attributes are investigated.
Data Normalization

» Expectation that data quality will be reviewed

» In order to analyze a set of wells, production data is typically normalized to time zero and ordered based on months on production. Month 1, Month 2, Month 3, etc.

» This is a relatively well understood concept but there are a few things to watch out for:
  » Wells with shut-in months in the middle of data set
  » Wells that are now shut-in (i.e. no longer producing or failures)
  » Calendar day vs. Producing day rates
  » Normalize to Peak Rate vs. Month 0
Wells with shut-in months in the middle of data set

Consider the scenario where a well is produced for a few months, shut in for 5 months and then produced again.
Data Normalization

Wells with shut-in months in the middle of data set

When we combine this well with another well (orange) and calculate the average (red) it creates an artificial dip in the average across those months.
Data Normalization

Wells with shut-in months in the middle of data set

Since the shut-in is clearly not representative of the reservoir’s capability in those months, we need to condition the data and “remove the zeros” before calculating the average. Now the resulting average profile is more representative of the two wells.
When you can confirm that the normalized rate per 100 m of length is consistent even when wells are getting longer with time, we can then adjust our EURs proportionally up for longer wells.
4) Additional Analysis

» Required to fully understand reservoirs
» Monograph 4 is not prescriptive that you require these tools for reserves but it is recommended under several circumstances such as important wells, lack of understanding of fluid phase, etc.
» It is especially recommended if it would have a meaningful impact on reserves
» RTA is limited to a single phase and well whereas numerical simulation can model multiple wells
RTA/Simulation

» RTA slow to be used due to poor data quality and failures to meet underlying model assumptions. As models expand, these shortcomings are being overcome. The chapter outlines the state of the art of generating the models and suggested workflow

» RTA seen as bridge between empirical and numerical methods

» Simulation allows integration of any classical reservoir engineering concept that can be tested against real pressure and production data. “Drainage radius” and “average reservoir pressure” must be used with caution.

» Simulation only as good as geological description.
5) Uncertainty

» **1P and 1C**: Proved reserves & Low est. contingent will have high degree of certainty of technical recoverability.

   *Future revisions should be mostly positive*

» **2P and 2C**: Proved + Probable reserves & Best est. contingent will have most likely level of technical recoverability.

   *Future revisions should be close to zero*

» **3P and 3C**: Proved + Probable + Possible reserves & High est. contingent will have low certainty of technical recoverability.

   *Future revisions should be mostly negative*

» **Tools for quantifying uncertainty:**
  » Semilog, log probit plots and histograms
  » Trumpet plot aggregation
  » Cumulative confidence interval plots
  » Sequential accumulation plots
Recall that many oil and gas results typically follow a log normal regression including IP rates and EUR. This is particularly true in resource plays.

The example below shows the EUR distribution of 100+ Montney wells and calculates a mean (average) of 8.4Bcf, P90 of 4.2Bcf and P10 of 13.9Bcf for a ratio of 50-100-166 percent.

These values represent expectations for a single well and do not include aggregation.
Workflow

» Suggested workflow:
  » Assess data viability and confirm correlation
  » Construct diagnostic plots
  » Identify flow regimes
  » Analyze and forecast with selected simple methods
  » Analyze and forecast with semi analytical models (RTA)
  » History match with simulator
  » Reconcile forecasts and estimate ultimate recoveries

» Provides examples targeting the Marcellus, Bakken and Eagle Ford
Securities Regulators – Relating to Reserves

Canada

CSA
(Canadian Securities Administrators)

ASC
(Alberta Securities Commission)

Year-End Proved Plus Probable Reserves

NI 51-101
COGEH

United States of America

SEC
(U.S. Securities and Exchange Commission)

Year-End Proved Reserves

Regulation S-K
Regulation S-X
Sarbanes Oxely (SOX)
Differences between US (SEC) and Canadian reporting (NI 51-101)

» Price Schedule
  > Reasonable outlook on future prices (CAD)
  > 12 month average price held constant (US)

» Reserves Disclosure Requirement
  > Proved + Probable (before and after royalty) required (CAD)
  > Proved (after royalty) only required (US)

» Proved Undeveloped Rules
  > No specific limit on years of PUDs (CAD)
  > 5 year limit unless “specific circumstances” (US)

» Ability to Fund Future Development
  > Assume unlimited funds (CAD)
  > Need to demonstrate ability and intent to fund (US)
Technology of Interest

» From Monograph 4:
  » Alternative decline methods
  » RTA
  » Numerical simulation

» SEC states that forecasts must be from “reliable technology”

» From SEC Regulation S-X, 4-10(a)(25)
  » “Grouping of one or more technologies (including computational methods) that has been field tested and demonstrated to provide reasonably certain results with consistency and repeatability in formation being evaluated or analogous information”

» Has not provided substantial guidance in comment letters. Up to issuer to prove that it is established technology
Conclusions

» Monograph 4 – provides substantial insight and suggested workflows in regards to analyzing and assessing producing unconventional wells

» A range of topics are covered and include reservoir, operational, conventional and alternative decline analysis, RTA and numerical simulation

» New methods to evaluate wells need to be demonstrated as “reliable technology” to the SEC. At this time, there is no blanket approval for specific methods – it is up to the discloser to prove to the SEC that “reliable technology” was used
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