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Methods of Reserves Estimates

• Arps decline curve method

• Calculating original volumetric gas-in-place and applying a recovery factor to estimate reserves.

• Conventional material balance models to estimate OGIP and applying a recovery factor to estimate reserves.

• History match well and/or field production with a reservoir simulator, and estimate future production and reserves with the calibrated model.
Arps Methodology & Assumptions

• Methodology for Estimating Gas Reserves
  – Plot gas production rate against time & history match existing production using Arps models
  – Extrapolate history-matched trend into future and estimate reserves using economic cutoffs

• Assumptions Implicit in Using Arps Equations
  – Extrapolation of best-fit curve through existing data is accurate model for future trends
  – There will be no significant changes in current operating conditions that might affect trend extrapolation
  – Well is producing against constant bottom hole flowing pressure
  – Well is producing from unchanging drainage area, i.e., the well is in boundary-dominated flow

- b-exponent of 1.3
- Reservoir abandonment pressure of 2000 psi
- Effective decline rate of 58%
- EUR estimate is 2.08 Bcf
Estimating Arps Decline Curve Parameters

1) \[ q(t) = \frac{q_i}{(1 + b D_i t)^{1/b}} \]  
   D_i is the initial decline rate, q_i is the gas flow rate, and b is the Arps decline curve constant or exponent.

2) \[ q(t) = \frac{q_i}{e^{D_i t}} = q_i e^{-D_i t} \]  
The exponential decline equation can be derived from Equation (1) with a b-exponent of zero.

3) \[ q(t) = \frac{q_i}{(1 + D_i t)} \]  
The harmonic decline is the special case of Equation (1) when the b-exponent equals one.

4) \[ q(t) = \frac{q_i}{(1 + b D_i t)^{1/b}} \]  
The hyperbolic decline which can be derived from Equation (1) when b is between 0 and 1.0

- The value of b determines the degree of curvature of the semilog decline, ranging from a straight line with b=0 to increasing curvature as b increases.

- Values of b greater than one reflected transient or transitional rather than true boundary-dominated flow.
Problem Statement

- Reserves in tight gas sands typically evaluated using Arps decline curve technique
- Reservoir properties preclude accurate reserve assessments using *only* decline curve analysis
- Errors most likely during early field development period before onset of boundary-dominated flow
Paper Objectives

• Develop reserves appraisal work-flow process to reduce reserve estimate errors in tight gas sands

• Work-flow process model should:
  – Allow continuous but reasonable reserve adjustments over entire field development life cycle
  – Prevent unrealistic (either too low or too high) reserve bookings during any field development phase
  – Be applicable during early development phases when reserve estimate errors are most likely and are largest
**Work-Flow Process Model Overview**

- **Model Attributes**
  - Captures characteristic tight gas sand flow and storage properties
  - Incorporates comprehensive data acquisition and evaluation programs
  - Integrates static and dynamic data types (*i.e.*, engineering, geological, and petrophysical) at all reservoir scales

- **Model Hypothesis**
  - Complement rather than replace traditional decline curve analysis with deterministic evaluation program
  - Reduce reserve estimate uncertainties and errors with integrated work-flow process model
Work-Flow Process Diagram

Static Pressures

Core Acquisition & Evaluation

Well Log Acquisition & Evaluation

Fluid Acquisition & Evaluation

Volumetric GIP (Static)

Contacted GIP (Dynamic)

Traditional Decline Curve Analysis

Quantification

Reserves

Validation

Flowing Pressures

Well Performance Analysis

Reservoir Simulation

Well Surveillance & Monitoring
<table>
<thead>
<tr>
<th>Field Development Stage</th>
<th>Type of Flow Period</th>
<th>Relationships Among Gas Volumes</th>
</tr>
</thead>
<tbody>
<tr>
<td>Early</td>
<td>Transient</td>
<td>$G_p &lt; CGIP &lt;&lt; EUR &lt; VGIP$</td>
</tr>
<tr>
<td>Intermediate</td>
<td>Transitional</td>
<td>$G_p &lt; CGIP &lt; EUR &lt; VGIP$</td>
</tr>
<tr>
<td>Late</td>
<td>Boundary-Dominated</td>
<td>$G_p &lt; EUR &lt; CGIP &lt; VGIP$</td>
</tr>
<tr>
<td>Abandonment</td>
<td>Boundary-Dominated</td>
<td>$G_p &lt; EUR &lt; CGIP &lt; VGIP$</td>
</tr>
</tbody>
</table>
Example Application of Work-Flow Process Model

- Granite Wash of TX Panhandle
- 2000’+ Gross Interval
- Sand Geometry: fan - delta
- Mixed lithology and layered
- Porosity range: 0% - 15%
- Permeability: 0.0001 - 0.1 mD
- Pressure gradient ~ 0.47 psi/ft
- Multiple frac stages required
Application of Work-Flow Process Model

Reserves Quantification Stage

Traditional Decline Curve Analysis

Contacted GIP (Dynamic)

Volumetric GIP (Static)

Reserves

Validation

Quantification

Static Pressures

Core Acquisition & Evaluation

Well Log Acquisition & Evaluation

Fluid Acquisition & Evaluation

Well Surveillance & Monitoring

Reservoir Simulation

Well Performance Analysis

Flowing Pressures

Well Log Acquisition & Evaluation

Core Acquisition & Evaluation

Fluid Acquisition & Evaluation

Static Pressures

Reserves Quantification Stage

Traditional Decline Curve Analysis
Decline Curve Analysis; 300 & 700 Day

300 day flow period

- $b$-exponent of 1.3
- Effective decline rate of 58%
- EUR estimate is 2.08 Bcsf
- $G_p = 0.465$ Bcsf gas, 15.5 Mbbl oil, and 27.1 Mbbl water.

Abandonment pressure of 2000 psi

700 day flow period

- $b$-exponent of 1.0
- Effective decline rate of 38.8%
- EUR estimate is 1.359 Bcsf
- $G_p = 0.69$ Bcsf gas, 21.3 Mbbl oil, and 33.4 Mbbl water.
Application of Work-Flow Process Model

Reserves Validation Stage
Computing Volumetric Gas-in-Place (VGIP)
Key Data Requirements

- **Well and Reservoir Surveillance & Monitoring Program**
  - Initial BHPs required to compute VGIP
  - Initial and subsequent BHPs required to monitor flow periods during field development and compute CGIP

- **Core Acquisition Programs**
  - Recommend core samples be taken early in field development
  - Also recommend conventional whole core rather than sidewall cores taken through complete vertical sections
  - Use drilling fluids to minimize mud invasion and displacing connate water
Storage and Flow Capacity Assumptions

Traditional methods attempt to correlate storage capacity to EUR with little success.

Advanced analysis method correlates flow capacity to EUR.

**Reservoir Storage Capacity**

\[ GIP = 43560 \cdot A \cdot H \cdot \phi \cdot (1 - S_w) / B_o \]

**Expected Ultimate Recovery**

**Reservoir Flow Capacity**

\[ P_i = \frac{Q}{P_i - P_{rh}} = \frac{K_{eff} \cdot H \cdot \alpha}{\mu \cdot B_o \cdot \ln \left( \frac{R_e}{R_w} \right)} \]
Dynamically Calibrated Net Pay Thickness

- Integrate log-based $K_{eff}$, then
- Match log-based $K_{eff}$ to recorded PL gas in-flow, by
- Altering net pay threshold criteria (e.g. $\phi$, $Sw$, $K_{eff}$)
The reduction in gross to net ratios is a direct result of the loss of porosity and permeability by diagenesis and diminishes the connected or effective drainage area.

Well spacing is commonly used as the area for estimating initial VGIP (80 ac).

VGIP was updated ~ 12.7 Bcsf by multiplying the net pay/gross interval ratio by the initial spacing.
Application of Work-Flow Process Model

Reserves Validation Stage
Computing Contacted Gas-in-Place (CGIP)
Flowing Material Balance Analysis

300 Day Flow Period
- CGIP = 1.042 Bscf
- Contacted area = 6.27 acres

700 Day Flow Period
- CGIP = 1.215 Bscf
- Contacted area = 7.31 acres
Rate Transient Analysis; CGIP, k, F_h

300 Day Flow Period
- CGIP = 1.038 Bscf
- Contacted area = 6.25 ac
- $k_{eff} = 0.0043$ mD
- $F_h = 147$'

700 Day Flow Period
- CGIP = 1.2 Bscf
- Contacted area = 7.25 ac
- $k_{eff} = 0.004$ mD
- $F_h = 158$'
Rate Transient Analysis Summary

- CGIP increases by 20%
- Contacted area also increases
- Fracture half length increases
- The core-log model effective permeability of 0.0031 mD is very close to the average decline type-curve solution of 0.0029 mD.

### 300 Day Flow Period: Analysis Type

<table>
<thead>
<tr>
<th>Type</th>
<th>CGIP</th>
<th>Area</th>
<th>Permeability</th>
<th>Frac Half Length</th>
</tr>
</thead>
<tbody>
<tr>
<td>Blasingame - Fracture</td>
<td>1.04</td>
<td>6.25</td>
<td>0.0043</td>
<td>147.134</td>
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<tr>
<td>Agarwal-Gardner - Fracture</td>
<td>1.03</td>
<td>6.2</td>
<td>0.002</td>
<td>293.305</td>
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<tr>
<td>Transient: Finite Conductivity</td>
<td>1.05</td>
<td>6.33</td>
<td>0.0027</td>
<td>262.505</td>
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<tr>
<td>NPI: Fracture</td>
<td>1.05</td>
<td>6.33</td>
<td>0.0022</td>
<td>296.211</td>
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<tr>
<td>Flowing Material Balance</td>
<td>1.04</td>
<td>6.27</td>
<td></td>
<td></td>
</tr>
<tr>
<td><strong>Averages</strong></td>
<td>1.042</td>
<td>6.276</td>
<td>0.0028</td>
<td>249.78875</td>
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</tbody>
</table>

### 700 Day Flow Period: Analysis Type

<table>
<thead>
<tr>
<th>Type</th>
<th>CGIP</th>
<th>Area</th>
<th>Permeability</th>
<th>Frac Half Length</th>
</tr>
</thead>
<tbody>
<tr>
<td>Blasingame - Fracture</td>
<td>1.2</td>
<td>7.25</td>
<td>0.004</td>
<td>158.556</td>
</tr>
<tr>
<td>Agarwal-Gardner - Fracture</td>
<td>1.21</td>
<td>7.31</td>
<td>0.0019</td>
<td>318.427</td>
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<tr>
<td>Transient: Finite Conductivity</td>
<td>1.22</td>
<td>7.32</td>
<td>0.0039</td>
<td>282.365</td>
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<tr>
<td>NPI: Fracture</td>
<td>1.21</td>
<td>7.25</td>
<td>0.0021</td>
<td>317.138</td>
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<tr>
<td>Flowing Material Balance</td>
<td>1.22</td>
<td>7.31</td>
<td></td>
<td></td>
</tr>
<tr>
<td><strong>Averages</strong></td>
<td>1.212</td>
<td>7.288</td>
<td>0.002975</td>
<td>269.1215</td>
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Application of Work-Flow Process Model

Reserves Validation Stage

Reservoir Simulation; Estimation of Drainage Area & EUR
Reservoir Simulation Workflow

I. Input core-log-based intrinsic reservoir layer properties into RTA

II. Fracture dimensions, conductivity and effective permeability from Rate Transient Analysis

III. Numerical reservoir simulation where the drainage area is controlling variable. All other inputs have been constrained from the core-log and rate transient analysis.
8 acre drainage area is the best match

< 80 acre well spacing

> than the contacted area observed at the 300 (1.04 ac) and 700 (1.21 ac) day RTA analysis

EUR = 1.06 Bscf at day 10000
### Reservoir Simulation Summary

<table>
<thead>
<tr>
<th>Flow Period</th>
<th>Drainage Area(^1)</th>
<th>Produced Gas, (G_p)</th>
<th>Contacted Gas-In-Place, (CGIP)</th>
<th>(^2) Expected Ultimate Recovery, (EUR)</th>
<th>(^3) Volumetric Gas-In-Place, (VGIP)</th>
</tr>
</thead>
<tbody>
<tr>
<td>Days</td>
<td>acres</td>
<td>Bscf</td>
<td>Bscf</td>
<td>Bscf</td>
<td>Bscf</td>
</tr>
<tr>
<td>0</td>
<td>80</td>
<td>0</td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>300</td>
<td>12</td>
<td>0.465</td>
<td>1.04</td>
<td>1.06</td>
<td>1.913</td>
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<tr>
<td>700</td>
<td>8</td>
<td>0.69</td>
<td>1.21</td>
<td>1.06</td>
<td>1.294</td>
</tr>
<tr>
<td>10000</td>
<td>8</td>
<td>1.06</td>
<td>1.21</td>
<td>1.06</td>
<td>1.294</td>
</tr>
</tbody>
</table>

\(^1\) Drainage area would not normally change. Down scaling of area is indicative of uncertainty in the knowledge of geology and the impact of pore disconnection due to diagensis on effective drainage area.

\(^2\) EUR estimated from 10000 day numeric reservoir simulation

\(^3\) VGIP is decreasing due to decreases in estimated drainage area.

### Fluid Relationships

<table>
<thead>
<tr>
<th>Flow Period, Days</th>
<th>Fluid Relationships</th>
<th>Type of Flow Period</th>
<th>Stage of Production</th>
</tr>
</thead>
<tbody>
<tr>
<td>300</td>
<td>(G_p &lt; CGIP &lt;&lt; EUR &lt; VGIP)</td>
<td>Transient</td>
<td>Early</td>
</tr>
<tr>
<td>700</td>
<td>(G_p &lt; EUR &lt; CGIP \leq VGIP)</td>
<td>Boundary-Dominated</td>
<td>Late</td>
</tr>
<tr>
<td>10000</td>
<td>(G_p = EUR \leq CGIP \leq VGIP)</td>
<td>Boundary-Dominated</td>
<td>Abandonment</td>
</tr>
</tbody>
</table>
Summary & Conclusions

• Developed reserves appraisal work-flow process specifically for tight gas sands

• Work-flow process

  – Designed specifically to incorporate tight gas sand production characteristics

  – Intended to complement rather than replace traditional decline curve analysis

  – Integrates both static and dynamic data with appropriate evaluation techniques
• Work-flow is adaptive process that allows continuous but reasonable reserve adjustments over entire reservoir life cycle

• Process is most beneficial during early field development stages before boundary-dominated flow conditions have been reached and when reserve evaluation errors most likely
Thank You