PROBABILISTIC NODAL ANALYSIS AND ECONOMIC APPRAISAL OF CASCADE & CHINOOK DEEPWATER FIELD DEVELOPMENT TO OPTIMIZE DECISION MAKING

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Motivation

• North America petroleum industry focus has been on unconventional reservoirs
• Federal Offshore oil production accounts for 10% of US oil production
• Determine the optimum field development option for an ultra-deepwater field (GoM)
• Volatility of oil prices may threaten profitability of offshore projects more than onshore projects
Outline

• Cascade and Chinook fields
• Methodology
  ▪ Nodal Analysis
  ▪ Economic Appraisal
• Results
  ▪ Sensitivity Analysis
• Conclusions
1. Cascade and Chinook Fields
Cascade and Chinook

- Discovered in 2002, started production in 2012
- Located 160 miles south of Louisiana
- Water depths greater than 8,000 ft
- Far from existing pipeline infrastructure
Pipeline Infrastructure in GoM
FPSO Solution

- Shell was first to use FPSO in Spain 1977
- Petrobras uses FPSOs in Brazil since 1978
- FPSO first used in GoM in 2008
- Requirements of Jones Act (1920) discouraged use of FPSO; shuttle tanker needs to be:
  - US built
  - US crewed
  - 75% US owned
Production and Reservoir Characteristics

- Cascade produces since Feb 2012, 3 wells producing
- Chinook produces since Sep 2012, 1 producing well
- Both produce from Wilcox 1 and Wilcox 2
- GOR of 200 scf/STB
- Initial Pressure 19,000 psi and temperature 250°F
2. Methodology
Nodal Analysis

• Used to optimize field development
• Provides an accurate production forecast taking into account
  ▪ Every component in the system
  ▪ Reservoir parameters
  ▪ Production facilities
• Equates fluid inflow from the reservoir and fluid outflow to the production system at bottom of the well
Physics at Pwf

\[ \Delta p_4 = \bar{p}_R - p_s = \text{Loss in flowline} \]
\[ \Delta p_3 = p_{wf} - p_{wh} = \text{Loss in tubing} \]
\[ \Delta p_2 = p_{wfs} - p_{wf} = \text{Loss in completion} \]
\[ \Delta p_1 = \bar{p}_R - p_{wfs} = \text{Loss in reservoir} \]
\[ \Delta p_T = \bar{p}_R - p_s = \text{Total pressure loss} \]
Deterministic Fluid Inflow

- Assume cylindrical reservoir space to calculate \( r_e \)

\[
A_{\text{reservoir}} = \frac{5.615 NB_{oi}}{\phi(1 - S_w)h} \Rightarrow A_{\text{well}} = \frac{A_{\text{reservoir}}}{\text{number of wells}} \Rightarrow r_e \quad (1)
\]

- Use Darcy’s equation above the bubble point

\[
q_o = J(\bar{p}_r - p_{wf}) \quad (2)
\]

\[
J = \frac{kh}{141.2 B_o \mu_o \left[ \ln \left( \frac{r_e}{r_w} \right) - \frac{3}{4} + s \right]} \quad (3)
\]

- Vogel’s equation below the bubble point

\[
q_o = J(\bar{p}_r - p_b) + \frac{Jp_b}{1.8} \left[ 1 - 0.2 \frac{p_{wf}}{p_b} - 0.8 \left( \frac{p_{wf}}{p_b} \right)^2 \right] \quad (4)
\]
Inflow-Outflow Relationship

- Based on the node at $p_{wf}$
  - $p_{wf\text{ available}}$ – pressure provided by the reservoir
  - $p_{wf\text{ required}}$ – pressure needed for fluid to reach the surface
- $p_{wf\text{ available}} = p_{wf\text{ required}}$

\[ P_e - P_{wf\text{ available}} = \frac{q}{J} \]

\[ P_{wf\text{ required}} = \Delta P_{PE} + \Delta P_f + P_{wh} \]
Deterministic to Probabilistic

- $J$ contains key reservoir parameters

\[
P(A_{\text{reservoir}}) = \frac{5.615NB_{oi}}{P(\phi)(1 - S_w)P(h)} \Rightarrow P(r_e) \quad (1)
\]

\[
J = \frac{q}{P_e - P_{wf}}
\]

\[
P(J) = \frac{P(k)P(h)}{141.2B_o(t)P(\mu_o(t))} \left[ \ln \left( \frac{P(r_e)}{r_w} \right) - \frac{3}{4} + s \right] \quad (2)
\]

\[
P(p_{PE}) = P(\rho_{API}) \times TVD \quad (3)
\]
**Probabilistic Inputs**

- We used @Risk to randomly generate probabilistic values for distributions (triangular)

<table>
<thead>
<tr>
<th>Parameter</th>
<th>Distribution</th>
<th>Cascade</th>
<th>Chinook</th>
</tr>
</thead>
<tbody>
<tr>
<td>Permeability, $k$ (mD)</td>
<td>![Image]</td>
<td>2-50</td>
<td>2-100</td>
</tr>
<tr>
<td>Net Pay, $h$ (ft)</td>
<td>![Image]</td>
<td>300-600</td>
<td>300-700</td>
</tr>
<tr>
<td>Viscosity, $\mu$ (cp)</td>
<td>![Image]</td>
<td>8-19</td>
<td>5-19</td>
</tr>
<tr>
<td>Porosity, $\phi$ (%)</td>
<td>![Image]</td>
<td>16-20</td>
<td>16-20</td>
</tr>
<tr>
<td>Oil Gravity (API)</td>
<td>![Image]</td>
<td>18-26</td>
<td>18-26</td>
</tr>
</tbody>
</table>
Density Functions

a) J Cascade

b) J Cascade

@RISK Course Version
Texas A and M Univ
# Probabilistic Production Index

<table>
<thead>
<tr>
<th>Cascade</th>
<th>J</th>
<th>Permeability (mD)</th>
<th>Height (ft)</th>
<th>Porosity (fraction)</th>
<th>API Gravity Oil</th>
<th>Oil viscosity @ Pi (cp)</th>
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</thead>
<tbody>
<tr>
<td>P90</td>
<td>0.20</td>
<td>9.99</td>
<td>398.8</td>
<td>0.1660</td>
<td>24.0</td>
<td>17.31</td>
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<tr>
<td>P50</td>
<td>0.53</td>
<td>25.87</td>
<td>446.8</td>
<td>0.1880</td>
<td>23.9</td>
<td>19.26</td>
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<tr>
<td>P10</td>
<td>1.14</td>
<td>32.08</td>
<td>589.2</td>
<td>0.1774</td>
<td>21.8</td>
<td>14.74</td>
</tr>
<tr>
<td>Chinook</td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>P90</td>
<td>0.38</td>
<td>10.47</td>
<td>532.7</td>
<td>0.1775</td>
<td>23.4</td>
<td>12.26</td>
</tr>
<tr>
<td>P50</td>
<td>1.11</td>
<td>35.38</td>
<td>562.4</td>
<td>0.1675</td>
<td>19.4</td>
<td>15.13</td>
</tr>
<tr>
<td>P10</td>
<td>2.42</td>
<td>77.66</td>
<td>528.4</td>
<td>0.1820</td>
<td>20.9</td>
<td>14.31</td>
</tr>
</tbody>
</table>
Deterministic vs Probabilistic History Matching

**Deterministic**

- Accumulative production
- Calculated accumulative production

**Probabilistic**

- Accumulative production
- Accumulative Production P50
- Accumulative Production P90
- Accumulative Production P10
<table>
<thead>
<tr>
<th>Parameter</th>
<th>Value</th>
</tr>
</thead>
<tbody>
<tr>
<td>Initial reservoir temperature</td>
<td>250 °F</td>
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<tr>
<td>Initial reservoir pressure</td>
<td>19000 psi</td>
</tr>
<tr>
<td>Bubble Point Pressure</td>
<td>1000 psi</td>
</tr>
<tr>
<td>Total compressibility Factor</td>
<td>3.0E-05 psi⁻¹</td>
</tr>
<tr>
<td>Permeability</td>
<td>35 mD</td>
</tr>
<tr>
<td>Height</td>
<td>562 ft</td>
</tr>
<tr>
<td>Skin factor</td>
<td>0</td>
</tr>
<tr>
<td>Total Oil in Place</td>
<td>2.49E+08 BOE</td>
</tr>
<tr>
<td>Water Saturation - initial</td>
<td>0.35</td>
</tr>
<tr>
<td>(\phi) - Porosity</td>
<td>0.167</td>
</tr>
<tr>
<td>Reservoir volume</td>
<td>2.41E+09 rb</td>
</tr>
<tr>
<td>Reservoir Volume in cubic feet</td>
<td>1.35E+10 ft³</td>
</tr>
<tr>
<td>Reservoir Area</td>
<td>2.41E+07 ft²</td>
</tr>
<tr>
<td>Reservoir Area per well</td>
<td>552.3 acres</td>
</tr>
<tr>
<td>Number of wells draining</td>
<td>1</td>
</tr>
<tr>
<td>Reservoir Area per well</td>
<td>552.3 acres</td>
</tr>
<tr>
<td>Drainage area radius, (r_e)</td>
<td>2767.3 ft</td>
</tr>
<tr>
<td>Wellbore diameter</td>
<td>7.625 in</td>
</tr>
<tr>
<td>Wellbore radius, (r_w)</td>
<td>0.318 ft</td>
</tr>
<tr>
<td>API Gravity Oil</td>
<td>19.4 °API</td>
</tr>
<tr>
<td>Oil specific gravity</td>
<td>0.938</td>
</tr>
<tr>
<td>Gas Specific Gravity</td>
<td>0.70</td>
</tr>
<tr>
<td>Oil viscosity @ (p_i)</td>
<td>15.1 cp</td>
</tr>
<tr>
<td>Compressibility Oil</td>
<td>1.5E-05 psi⁻¹</td>
</tr>
<tr>
<td>(B_{bb}) - (Oil FVF @ (p_b))</td>
<td>1.380 rb/stb</td>
</tr>
<tr>
<td>(B_{oi}) - (Oil FVF @ (p_i))</td>
<td>1.053 rb/stb</td>
</tr>
<tr>
<td>(B_{wi}) - (water FVF @ (p_i))</td>
<td>1.030 rb/stb</td>
</tr>
</tbody>
</table>
Probabilistic Production Forecasts

<table>
<thead>
<tr>
<th>Natural Drive</th>
<th>OOIP</th>
<th>P90</th>
<th>P50</th>
<th>P10</th>
</tr>
</thead>
<tbody>
<tr>
<td>Cascade</td>
<td>191</td>
<td>37.4</td>
<td>45</td>
<td>45.8</td>
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</tbody>
</table>

<table>
<thead>
<tr>
<th>Natural Drive</th>
<th>OOIP</th>
<th>P90</th>
<th>P50</th>
<th>P10</th>
</tr>
</thead>
<tbody>
<tr>
<td>Chinook</td>
<td>249</td>
<td>37.8</td>
<td>53.8</td>
<td>60.6</td>
</tr>
</tbody>
</table>
Collect monthly production data and reservoir properties

Develop Nodal Analysis model to forecast production

Sensitivity analysis on how reservoir parameters will affect production

Develop cash flow model to analyze economic outcome

Gather fiscal regime information

Simulate project costs (CAPEX, OPEX)

Perform sensitivity analysis on oil prices

Risk analysis on the project

Recommendations
3. Results
## Field Development Options

Appraised Probabilistically

<table>
<thead>
<tr>
<th></th>
<th>Description</th>
</tr>
</thead>
<tbody>
<tr>
<td>1</td>
<td>Cascade current development 3 wells Natural Drive</td>
</tr>
<tr>
<td>2</td>
<td>Cascade 3 wells Artificial Lift</td>
</tr>
<tr>
<td>3</td>
<td>Chinook current development 1 well Natural Drive</td>
</tr>
<tr>
<td>4</td>
<td>Chinook 1 well Artificial Lift</td>
</tr>
<tr>
<td>5</td>
<td>Chinook 2 wells Natural Drive</td>
</tr>
<tr>
<td>6</td>
<td>Chinook 2 wells Artificial Lift</td>
</tr>
<tr>
<td>7</td>
<td>Chinook 3 wells Natural Drive</td>
</tr>
<tr>
<td>8</td>
<td>Chinook 3 wells Artificial Lift</td>
</tr>
</tbody>
</table>
Recapture Cascade and Chinook Development Options

- All field development options were considered using natural drive (ND) and artificial lift (AL)
- Cascade was analyzed with two options: Option 1 (ND) and 2 (AL)
- Chinook is the larger field; currently only 1 producing well: Option 3 (ND) and 4 (AL)
- 2 other Option 5 (ND) and 6 (AL): 2 producing wells
- Option 7 (ND) and 8 (AL): 3 producing wells
Base Case Assumptions

- Field development costs were estimated using FieldPlan
- Historic oil prices were used until 2016
- Forward oil price is $60 per barrel with 2.5% annual inflation
- 12.5% Royalty
- 35% Corporate income tax
Current Development NPV@10

Options 1 and 2

Cascade: artificial lift (Option 2) more economic ($60/bbl)

Options 3 and 4

Chinook: natural drive (Option 4) less risky ($60/bbl)
Chinook P50 Comparison
$60/bbl

Option 3

Option 4

Option 5

Option 6

Option 7

Option 8

NPV@10 MM$

Natural Drive
Artificial Lift
Probabilistic NPV10 Comparison of all Options $60/bbl

- **Cascade**: artificial lift (Option 2) most economic

- **Chinook**: 2 wells artificial lift (Option 6) best development option

- Using nodal analysis can help determine the reservoir or production system bottleneck
Oil Price Sensitivity Option 2: Cascade 3 wells Artificial Lift P50

NPV vs Oil Price

- Contractor NPV @ 10 (MM$)
- Government Take (MM$)
- Contractor NPV + Government Take
- Contractor NPV (MM$)
Annual Cash Flow Option 2
Cascade $60/bbl
Oil Price Sensitivity Option 6: Chinook 2 wells Artificial Lift P50

NPV vs Oil Price

- Contractor NPV @ 10 (MM$)
- Government Take (MM$)
- Contractor NPV + Government Take
- Contractor NPV (MM$)
Annual Cash Flow Option 8
Chinook $60/bbl
Conclusions

• Probabilistic Nodal Analysis can be used for production forecasting and to determine the optimum field development
• P50 estimates show Chinook should be produced with 2 wells
• Nodal analysis can identify production limiting factors
• The use of FPSO will become more popular as the Mexican side of GoM is developed
Questions?
Future Work

- Automatization and integration of the nodal analysis and cash flow models.
- Using other sampling methods to calculate the probabilistic $J$
- Using a risk factor to adjust the NPV
- Expand probabilistic input parameters to include Area of production tubing