THE KEY TO PREDICTIVE RESERVOIR SIMULATION OF EOR PROJECTS

Dubert Gutiérrez, AnBound Energy Inc.
Disclaimer

- All data used in this presentation were taken from the public domain.

- There was no involvement in this analysis of any of the past or current operators of the fields, pilots and projects being discussed.

- Views, thoughts, analyses, and opinions expressed in this presentation belong solely to the author, and not to the author’s employer or any other company.
Similarities Between an EOR Project and a Spouse

Sometimes I think you don't listen to a word I say!

What wives say...

...go to the store; lay down the mulch; wash and wax the car; get the kids at school; rent some videos, and finish the rest of the dishes.

What husbands hear...

...go in the store; lay down the mulch, wax, wash car; get the kids at school; rent some videos, and finish the rest of the dishes.

Honey, I can not find my slippers!

Wait a moment! I try it with Google!
Outline

- Hot Water Injection Pilot (SPE-174491-PA)
- Water Injection & Polymer Injection (SPE-165234-PA)
- In-Situ Combustion Pilot (SPE-174455-PA)
Motivation

- Laboratory data often treated as “gospel” in field-scale EOR modelling

- Increase in use of data-driven analytical models, in isolation from physical theory

- Lack of predictability of history matched simulation models

- Modelling opportunity for EOR Pilots
  - Data availability and advancements in reservoir simulation technology (i.e. hardware and software)
Hot Water Injection in the Pelican Lake Field (Alberta)

- Discovered: 1978
- Wabiskaw “A” sand
- Thin formation: two to six meters
  - Oil viscosity: 600 to 80,000+ cp
- Horizontal drilling: late 1980s
- Multilateral wells: early 1990s
- Waterflood: early 2000s
- Polymer injection: mid 2000s
- Hot water injection pilot: June 2011

### TABLE 1—WABISKAW RESERVOIR CHARACTERISTICS

<table>
<thead>
<tr>
<th>Property</th>
<th>Value</th>
</tr>
</thead>
<tbody>
<tr>
<td>Depth</td>
<td>300–450 m (985–1,475 ft)</td>
</tr>
<tr>
<td>Thickness</td>
<td>1–9 m (3–30 ft)</td>
</tr>
<tr>
<td>Porosity</td>
<td>28–32%</td>
</tr>
<tr>
<td>Permeability</td>
<td>300–5,000 md (300–5,000 md)</td>
</tr>
<tr>
<td>Oil saturation</td>
<td>60–70%</td>
</tr>
<tr>
<td>Temperature</td>
<td>12–17°C (54–63°F)</td>
</tr>
<tr>
<td>Initial pressure</td>
<td>1800–2600 kPa (260–380 psi)</td>
</tr>
<tr>
<td>Oil gravity</td>
<td>11.5–16.5°API (11.5–16.5°API)</td>
</tr>
<tr>
<td>Solution Gas/Oil Ratio</td>
<td>4–6 m³/m³ (22–34 scf/STB)</td>
</tr>
<tr>
<td>Dead-Oil viscosity</td>
<td>800–80,000 cp (800–80,000 cp)</td>
</tr>
<tr>
<td>Live-Oil viscosity</td>
<td>600–50,000 cp (600–50,000 cp)</td>
</tr>
</tbody>
</table>

After SPE-165234-PA
Overview of Hot Water Injection Pilot

- 3 Horizontal wells
  - 2 Hot water injectors (edges)
  - 1 Producer (middle)

- 3 Vertical observation wells

- Hot water circulation in producer
  - Insulated coiled tubing
  - Hot fluid is delivered to the toe of the producer
  - Oil is stimulated/mobilized through conduction heating

Fig. 4—Phase 3: hot-water injection and circulation.
Mechanics of Hot Water Circulation

After
http://www.majus.co.uk/products/tor
## Oil Viscosity Variation in Pilot Area

<table>
<thead>
<tr>
<th>Well</th>
<th>Test Date</th>
<th>°API at 15°C</th>
<th>Oil Viscosity at 15°C (cp)</th>
</tr>
</thead>
<tbody>
<tr>
<td>Heel Observation Well</td>
<td>9 December 2011</td>
<td>13.4</td>
<td>9,166</td>
</tr>
<tr>
<td>100/12-32</td>
<td>12 April 2012</td>
<td>13.2</td>
<td>8,218</td>
</tr>
<tr>
<td></td>
<td>12 April 2014</td>
<td>13.2</td>
<td>8,462</td>
</tr>
<tr>
<td>Middle Observation</td>
<td>9 December 2011</td>
<td>14.8</td>
<td>4,316</td>
</tr>
<tr>
<td>Well 100/09-32</td>
<td>12 April 2012</td>
<td>15.4</td>
<td>2,446</td>
</tr>
<tr>
<td></td>
<td>12 April 2014</td>
<td>16.6</td>
<td>1,233</td>
</tr>
<tr>
<td>Toe Observation Well</td>
<td>9 December 2011</td>
<td>15.5</td>
<td>2,517</td>
</tr>
<tr>
<td>100/11-33</td>
<td>12 April 2012</td>
<td>15.6</td>
<td>1,977</td>
</tr>
<tr>
<td></td>
<td>12 April 2014</td>
<td>15.8</td>
<td>1,832</td>
</tr>
</tbody>
</table>

Table 1—Observation-well produced-oil viscosity.

---

Fig. 9—Chip-sample viscosities along well paths.
Reservoir Simulation Challenges & Opportunities

- **Good news**
  - Structurally very simple
  - Reservoir properties at pilot site seem uniform and consistent between wells
  - A simple homogeneous (but anisotropic) “box” model could be used
  - Good field data gathering and pilot surveillance

- **Not so good news**
  - Heterogeneity in oil viscosity in pilot area
  - *Viscosity of produced oil samples are not representative of in-situ reservoir oil (i.e. lighter oil fractions are produced while heavier fractions remain in-situ)*
  - Conventional oil viscosity modeling approach might not be appropriate
How to Model Oil Viscosity Distribution?

- 3 Different oil viscosity distributions were considered. What is the in-situ oil viscosity required to obtain the produced oil viscosity?

Reservoir Simulation Models – Live Oil Viscosity

Fig. 17—Plan view of different oil-viscosity models (live-oil viscosity).
History Matching Results – After SPE-174491-PA

Fig. 20—Produced-oil viscosity.

Fig. 18—BHP of thermal injector.

Fig. 21—Heel-observation-well pressure.

Fig. 23—Toe-observation-well pressure.

Fig. 22—Middle-observation-well pressure.

Fig. 25—Water cut in circulation well.
Reservoir Simulation Forecasts

- History match until Oct. 2012
  - Oil rate constrained: Start to Aug. 2012

- Forecast since Nov. 2012
  - Updated injection/downtime: Oct. 2013

- Models were used to optimize pilot operation and maximize learnings (forward blind test)
  - Increase circulation temperature from 100 °C to 180 °C in July 2013

- Heterogeneous oil viscosity models provide better representation and more accurate forecasts

After SPE-174491-PA
Water & Polymer Injection in the Pelican Lake Field (Alberta)

Fig. 25—Polymer-flood development on CNRL lands.

Fig. 23—Comparison of oil rate in CNRL waterflood and polymer-flood pilots.

Fig. 19—Injection rate and pressure for one of the two polymer-injection wells in HTLP 6 (from CNRL 2018).

Fig. 24—Comparison of water cut in CNRL waterflood and polymer-flood pilots.
Reservoir Simulation Challenges & Opportunities

- Challenges in a few pads
  - Wellhead injection pressure increasing more rapidly than originally forecasted by reservoir simulations
  - Liquid production lower than forecasted by reservoir simulations

- Opportunities
  - Long production/injection history
  - Availability of laboratory data (water compatibility, corefloods, polymer adsorption, polymer rheology, etc.)
What is Happening in the Field? Why is the Model not Working?

- **Different hypotheses**
  - Incorrect petrophysical and/or SCAL assumptions
  - Formation damage (e.g. clay swelling, polymer degradation)
  - Reservoir dilation (i.e. geomechanical effects)

- **Unsuccessful to resolve using a “conventional” simulation approach. A “different” approach was attempted**
  - What do I need to do to the model to replicate the observed behaviors?
  - Try to identify possible causes by history matching different scenarios
  - Is any of the scenarios physically sound? What is the field trying to tell us?
  - Test hypothesis by performing blind tests
Further Observations

- Anomalous behaviors were not necessarily exclusive to the polymer injection phase
  - Challenge was magnified during polymer injection
  - Need to re-visit plausible causes

- Some of the scenarios considered
  - Formation damage due to “fines migration” based on CMG’s model
  - Reservoir dilation and increase of reservoir pore volume
  - A combination of the above two mechanisms
Scenario 1 – Fines Migration Only

Water blockage due to “fines migration” is used to hold water near injectors. Dilation is minimal and equal in all directions (isotropic)
Scenario 2 – Reservoir Dilation

Water is held back (near injectors) by dilating in K and J directions (not towards the producer)

J Direction: Parallel to the injector
K Direction: Vertical Direction
Scenario 3 – Combination of the Two Mechanisms

Water is held back (near injectors) by:
1. Blocking due to fines
2. Dilating in an IJ “angle”, mostly in the J direction
Further Analyses and Comments

- All 3 scenarios seemed possible. However:
  - A blind test in the model can assist in identifying most plausible one
  - Testing of model in other pads can assist in confirming the main mechanisms or identifying differences in different pads

- Well tests can be designed to test hypotheses, and further understand reservoir behavior

- Additional laboratory work can be performed to identify source of the problem in specific pads
In-Situ Combustion Pilot – Process Overview (EnCAID & AIDROH)
# Reservoir Properties & Site Layout

<table>
<thead>
<tr>
<th>Property</th>
<th>Value</th>
</tr>
</thead>
<tbody>
<tr>
<td>Formation</td>
<td>Wabiskaw</td>
</tr>
<tr>
<td>Depth</td>
<td>465 m</td>
</tr>
<tr>
<td>Thickness</td>
<td>25-30 m</td>
</tr>
<tr>
<td>Porosity - Average</td>
<td>35%</td>
</tr>
<tr>
<td>Oil Saturation - Average</td>
<td>65%</td>
</tr>
<tr>
<td>Permeability - Average</td>
<td>1,350 mD</td>
</tr>
<tr>
<td>Oil Viscosity @ 13 °C</td>
<td>~35,000 cP</td>
</tr>
</tbody>
</table>

![Fig. 3—AIDROH-pilot well layout.](image-url)
Temperature Profiles in Observation and Production Wells

Fig. 4—Observation-well temperatures with time.

Fig. 8—Temperature along the AIDROH well at various times.
Reservoir Simulation Challenges & Opportunities

- **Challenges**
  - Unexpected temperature behavior in gas cap
    - Two temperature peaks
    - Tilted combustion front
    - Different shapes of temperature peaks
    - Unexplained by laboratory experiments
  - Complex process (chemical reactions, etc.)
  - It requires a fine simulation grid
  - Long simulation run times

- **Opportunities**
  - Successful ignition and combustion performance
  - Outstanding surveillance data
  - Heating of oil zone was mostly through thermal conduction (simpler process)
Temperature History Match – Heater Model

Fig. 18—Simulated temperature (°C) at 15 m into the bitumen at the end of 2014—heater model.

Fig. 17—Simulated temperature in the observation well—heater model.
Simulation History Match & Production Forecast – Single Reaction Model

Fig. 20—Simulated temperature (°C) 1 m into the bitumen at the end of 2014—in-situ-combustion model.

After SPE-174455-PA

Fig. 19—Simulated oil-production performance—in-situ-combustion model.
Conclusions

- Analyzing the raw data to understand project performance by “listening to the field”, proved to be key to improving the predictability of reservoir simulation models.

- Surveillance and monitoring of EOR pilot projects is of extreme importance to their success and need to be designed and analyzed carefully.
  - Laboratory data is important but let’s remember to listen to the field.

- Remember to blind-test your models (i.e., “Forecast” known results).

- Run pilot as a “controlled” experiment (i.e., forward blind testing).
  - Use model to design experiment and compare forecast with actual results.

- This exercise is made simpler by the use of current simulation technology (assisted history matching, parallel computing, faster hardware, etc.), which allows us to evaluate/run multiple scenarios and perform multiple sensitivities, relatively easily.
Acknowledgements

- Past and current operators of the fields and their publications on the pilots and projects discussed
Thank You – Questions?
THE KEY TO PREDICTIVE RESERVOIR SIMULATION OF EOR PROJECTS

Dubert Gutiérrez, AnBound Energy Inc.