The Timber Creek Field Study for Improving Waterflooding

Prepared for the EORI Joint EOR Commission & Technical Advisory Board Meeting

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Project Summary and Timeline

• A collaborative study between EORI and Merit Energy Company under the Minnelusa Consortium
• The primary objective of the project is to evaluate various development plans for improving the waterflooding in its Minnelusa Reservoir
• The Timber Creek Field Geologic Study was completed by Gene George in Feb. 2010
• The Modeling and Simulation Study was started in Nov. 2009 and a final report was submitted to Merit in Feb. 2011
• A new injector was drilled in late 2011, named Gene George #1, and water injection initiated in Oct. 2012
• Monthly oil production has risen to 35,300 STBO/month in June 2013 from 16,800 STBO/month in Feb. 2010
• Currently collecting new data to update the Timber Creek Minnelusa model
Minnelusa Reservoirs in the Northern Powder River Basin

Timber Creek Field (T49N R70W)
# Oil and Reservoir Properties of the Minnelusa Reservoir at the Timber Creek Field

<table>
<thead>
<tr>
<th>Property</th>
<th>(B)</th>
<th>(C)</th>
</tr>
</thead>
<tbody>
<tr>
<td>Depth of Minnelusa Top</td>
<td>9100 ft</td>
<td></td>
</tr>
<tr>
<td>Initial Reservoir Pressure</td>
<td>3655 psi</td>
<td>3629 psi</td>
</tr>
<tr>
<td>Average Core Porosity</td>
<td>13.8%, 11.1%</td>
<td></td>
</tr>
<tr>
<td>Oil Gravity</td>
<td>31°, 27° API</td>
<td></td>
</tr>
<tr>
<td>Average Core Permeability</td>
<td>77 md, 47 md</td>
<td></td>
</tr>
<tr>
<td>Bubble Point Pressure (BPP)</td>
<td>770 psi, 599 psi</td>
<td></td>
</tr>
<tr>
<td>Average Gross Pay</td>
<td>60 ft, 50 ft</td>
<td></td>
</tr>
<tr>
<td>Gas Oil Ratio at BPP</td>
<td>85°, 65° SCF/STB</td>
<td></td>
</tr>
<tr>
<td>Average Net Pay</td>
<td>34.4 ft, 21.7 ft</td>
<td></td>
</tr>
<tr>
<td>Est. OOIP</td>
<td>35°, 20° MMBO</td>
<td></td>
</tr>
<tr>
<td>Oil Column</td>
<td>125 ft, 118 ft</td>
<td></td>
</tr>
<tr>
<td>Cum. Oil Production</td>
<td>14°, 6° MMBO</td>
<td></td>
</tr>
<tr>
<td>Oil/Water Contact</td>
<td>Various</td>
<td></td>
</tr>
<tr>
<td>Oil Recovery</td>
<td>40%, 30%</td>
<td></td>
</tr>
<tr>
<td>Reservoir Temperature</td>
<td>204°F</td>
<td></td>
</tr>
<tr>
<td>Well Spacing</td>
<td>40 acre</td>
<td></td>
</tr>
<tr>
<td>Primary Drive Mechanism</td>
<td>Water and solution gas</td>
<td></td>
</tr>
<tr>
<td>Est. CO2 MMP</td>
<td>3500 psi</td>
<td></td>
</tr>
</tbody>
</table>

(B): B Sand  
(C): C Sand
Typical Workflow in Reservoir Modeling & Simulation

Description of Reservoir Structure & Faults
Rock Facies & Flow Units
Fracture Network & Connection

Geologic Model (Petrel)

Well Logs
Well Completions
Core $\phi$, $K$, $Sw$, $So$
Seismic Survey

3D Grid System
$\phi$ & $K$ of Grids
Initial $So$, $Sg$, $Sw$

Simulation Model (Eclipse, CMG)

Laboratory Data
Fluid & Rock Properties: PVT, $Kro$, $Krw$, $Krg$, ...

Production & Injection History

History Matching

Remaining oil Distribution in Reservoir

Evaluation of EOR/IOR Floods

Operator Requests

Reports & Recommendations
Minnelusa Top and Possible Faults at Timber Creek Field
- By Gene George
Three B Sand Units (Sand Compartments) Identified by Gene George

**RED** = UPPER HIGH RESISTIVITY (>10 OHMS)
**BLUE** = MIDDLE LOWER RESISTIVITY (<10 OHMS)
**GREEN** = LOWER LOW RESISTIVITY (<3 OHMS)
The Model Boundary and the Three B Sand Units Mapped by Gene George

Aquifer Water Influx
What A Simulation Model Needs from A Geologic Model

- A structured grid system of the reservoir
  - It is desirable to configure flow units, e.g. sand compartments, as layers in the grid system
- Rock/formation properties of grids
  - Such as porosity and permeability
- Initial oil, gas, and water saturations of grids
  - Commonly estimated from Archie relations
Measured core porosity and water saturation in Cook, LeSueur and Campbell wells.
Measured core porosity and water saturation in Wolff, Toro and TC USA wells.
The 7-layer and 4-region Configuration of the Simulation Model for the Minnelusa Reservoir at Timber Creek Field
Loading Log and Core Measurements in Petrel
Modeled Minnelusa Structural Top at Timber Creek Field
A 3D View of the Layer and Grid Configuration
Grid pore volume distributions in the Red (top left), Blue (top right) and Green (bottom right) units of the B Sand.
Grid pore volume distributions in the Upper (top left), Middle (top right) and Lower (bottom right) units of the C Sand
Core Porosity-Permeability Correlation within Each Layer
A 3D View of the Porosity Distribution in the Model
A 3D View of the Permeability Distribution in the Model
Original Questions set for History Matching

- What would the initial oil-water contacts be in the B and C Sands and where does the oil remain today?
- How much is the C Sand contribution in the total oil production of wells that have commingled production from both B and C Sands?
- Can a good history matching be achieved without assuming fault-separated compartments?
- Aquifer water influx, from where and how much?
- How does fluid move among the 3 pods in the B Sand?
- Any infill drilling opportunities?
Some Data Issues in the History Matching

- A few BHP or fluid level measurements
- No gas production record before 1975
- About 2.8 million barrels of oil produced without gas producing records between 1975 and 1998
- Gaps in water producing records
- Only partial PVT report of the C sand oil
- No data of laboratory measured relative permeability
Timber Creek Field – Production History. This figure is copied from “Timber Creek Field: Exploitation Review”, an internal report of Merit Energy Company by Brad Bauer.
Well monthly oil production rates at Timber Creek Field
Well monthly water injection rates at Timber Creek Field

Monthly Water Injection Rate, BW/month

Fed 311-1
Fed 311-2
LeSueur #31-17
LeSueur #1-S
LeSueur #2-S
LeSueur #2
LeSueur #3-M
LeSueur #5
TC USA #2
Wolff #2
Wolff #3
Wolff #5

Time (Mar-60 to Dec-14)
Well Cumulative Production and Injection, as of June 2010

Legend
- Green: Cumulative Oil Production
- Blue: Cumulative Water Production
- Black: Cumulative Water Injection

Toro Fed #23-6

Wolff #5
Wolff #2
Wolff #3
Wolff #4

Toro #2
Toro #3

Cook #5
Cook #3/3R
Cook #2/2R

TC USA #2
TC USA #1

Fed #311-1
Fed #311-2

LeSueur #3M
LeSueur #2M
LeSueur #1M

LeSueur #1
LeSueur #2
LeSueur #1S

LeSueur #31-17

3 MMBW
Timber Creek Minnelusa: Pseudo Relative Permeability from History Matching

- Kro for B and C Sands
- Krw for B Sand
- Krw for C Sand

Sor = 0.3
Swr = 0.2
Observed (orange line) and simulated (green line) monthly rates of the field oil production.
Simulated reservoir average pressure (black) plotted with simulated (red) and reported (green) field GORs
Simulated and reported field water production rates

Simulated and reported cumulative field water productions
Fence diagram showing the initial oil saturation distribution in December 1962 (top) and the predicted oil saturation distribution in June 2010 (bottom) after history matching.
Findings from History Matching

• Drill-stem tests and oil PVT measurements reveal that the B and C Sand traps are separated oil systems.
• Mobile water initially existed in the C Sand pay intervals but almost no initial mobile water was in the B Sand pay intervals.
• The original oil-water contact in the B Sand varied from -4620 to -4714 feet subsea, trending higher in the southeast portion of the field and lower along its northwest flank. Tilted oil-water contacts were also observed in the C Sand, with a trend similar to the variation in the B Sand, and estimated to vary from -4721 to -4797 feet subsea.
• Both B and C Sands are producing under aquifer water drive, where the C Sand has more significant water influx support. The cumulative water influx into the B Sand, Upper C Sand unit and Lower C Sand unit are estimated to be 5.1, 3.3 and 7.9 MMBW, respectively.
• The B Sand volume in the static model derived from existing well controls appears to be smaller than the actual sand volume. In the history matching of the initial depletion, the pore volume of the B Sand had to be increased by 20% at the northern quadrant and 10% elsewhere to uphold a sustainable pressure decline.
Findings (cont’d)

• The resulting relative permeability curves from history matching indicate that the Minnelusa reservoir rock at Timber Creek Field is strongly water-wet.

• The lateral permeability in the B and C Sands was increased by a factor of 2 to 5 during the history matching to maintain the observed production rates. The increase in total permeability is most likely contributed by fractures, whereas the initial permeability distribution is estimated for matrix permeability only.

• A west-east fault may exist between Toro #1 and Toro #3. Both wells were perforated in the same B Sand unit with high resistivity. Toro #1 is wet but Toro #3 has produced very little water. Because Toro #1 was not included in the history matching, therefore, the effect of this conceivable fault was not evaluated in the simulation.

• Because of insufficient water injection volume during the production period between 1979 and 1998, the average reservoir pressure dropped below the bubble point pressure and caused very high producing GOR.
Findings (cont’d)

- Evident production response to cross-pod injectors suggests that the three B Sand bodies are at least partially connected. No any part of the field could be identified as a self-balanced production-injection region.

- The OOIP in the B Sand is estimated to be 35.4 MMBO, in which 13.9 MMBO have been produced, as of June 2010, a recovery rate of 39%.

- For the C Sand, the estimated OOIPs in the Upper and Lower sand units are 6.1 and 13.9 MMBO, respectively.

- There is some uncertainty in the estimation of OOIP for the C Sand, particularly for the Lower sand unit, due to limited well controls. It is estimated that 2.5 MMBO, or 41% of its OOIP, have been recovered from the Upper C Sand unit. In contrast, only 3.5 MMBO have been produced from the Lower C Sand unit with a much lower recovery rate of 25%. The entire C Sand contributed about 30% of the field total oil production.
Updated Isopach Map of Mid Lower B Sand
- from Gene George
Location of A Vertical Development Well Proposed by Merit
Location of A Horizontal Development Well Proposed by Merit
**Simulated Development Scenarios**

- **Case 1 (base case):** 40-year production under current production-injection scheme
- **Case 2:** drill a vertical production well
- **Case 3:** drill a horizontal production well
- **Case 4:** increase injection volume
- **Case 5:** reactivate Wolff #3
- **Case 6A:** convert Cook #1, Cook #4 and Wolff #1 to injectors
- **Case 6B:** Case 6A + converting Cook #3R to injector
- **Case 7A:** drill a new injector
- **Case 7B:** Case 7A + converting Cook #3R, Cook #4 and Wolff #1 to injectors
Field Daily Oil Rates of the 9 Simulated Scenarios

Case 7B with A new Vertical Injector
Field Cum. Oil Productions of the 9 Simulated Scenarios

- Case 7B with A new Vertical Injector
Estimated Oil Recovery of the Simulated Scenarios
(the best case in each category is highlighted in green)

<table>
<thead>
<tr>
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<tbody>
<tr>
<td></td>
<td>B &amp; C Sands</td>
<td>B Sand Only</td>
<td>B &amp; C Sands</td>
</tr>
<tr>
<td>Case 1</td>
<td>1.52</td>
<td>1.32</td>
<td>2.81</td>
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<tr>
<td>Case 2*</td>
<td>1.57</td>
<td>1.38</td>
<td>2.88</td>
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<tr>
<td>Case 3**</td>
<td>1.5</td>
<td>1.3</td>
<td>2.94</td>
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<tr>
<td>Case 4</td>
<td>1.75</td>
<td>1.47</td>
<td>3.15</td>
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<tr>
<td>Case 5</td>
<td>1.83</td>
<td>1.47</td>
<td>3.31</td>
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<tr>
<td>Case 6A</td>
<td><strong>2.3</strong></td>
<td><strong>2.08</strong></td>
<td><strong>3.62</strong></td>
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<tr>
<td>Case 6B</td>
<td>2.17</td>
<td>1.95</td>
<td>3.66</td>
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<tr>
<td>Case 7A***</td>
<td>1.9</td>
<td>1.65</td>
<td>3.31</td>
</tr>
<tr>
<td>Case 7B***</td>
<td>2.25</td>
<td>2.04</td>
<td><strong>3.91</strong></td>
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</table>

* Case 2 includes drilling a vertical production well
** Case 3 includes drilling a horizontal production well
*** Case 7A and Case 7B include drilling a vertical injector
Timber Creek Field: Monthly Oil Rate and Water Cut (since Jan. 2010)

- **Field Oil Rate**
- **Simulated Oil Rate of Case 7B**
- **Field Water Cut**

Injection initiated in Gene George #1
## Water Injection Status in June 2010, Case 7B, and June 2013

<table>
<thead>
<tr>
<th>Well Name</th>
<th>Well Status</th>
<th>Ave. Daily Injection Rate in June 2010</th>
<th>Targeted Injection Rate in Case 7B</th>
<th>Ave. Daily Injection Rate in June 2013</th>
</tr>
</thead>
<tbody>
<tr>
<td></td>
<td>June 2010</td>
<td>BWIPD</td>
<td>June 2010 BWIPD</td>
<td>June 2013 BWIPD</td>
</tr>
<tr>
<td>GENE GEORGE # 1</td>
<td>Shut-in</td>
<td></td>
<td>Injector 500</td>
<td>Injector 600</td>
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<tr>
<td>Cook # 1</td>
<td>Shut-in</td>
<td></td>
<td>Injector 500</td>
<td>Injector 600</td>
</tr>
<tr>
<td>Cook # 3R</td>
<td>Producer</td>
<td></td>
<td>Injector 500</td>
<td>Producer 318</td>
</tr>
<tr>
<td>Cook # 4</td>
<td>Producer</td>
<td></td>
<td>Injector 500</td>
<td>Producer 318</td>
</tr>
<tr>
<td>Fed 311 Camp # 1</td>
<td>Injector</td>
<td>1332</td>
<td>Shut-in 500</td>
<td>Shut-in 680</td>
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<tr>
<td>LeSueur # 2-S</td>
<td>Injector</td>
<td>1003</td>
<td>Injector 500</td>
<td>Injector 173</td>
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<tr>
<td>LeSueur # 3-M</td>
<td>Shut-in</td>
<td>160</td>
<td>Injector 400</td>
<td>Injector 708</td>
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<tr>
<td>Wolff # 1</td>
<td>Shut-in</td>
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<td>Injector 500</td>
<td>Injector 656</td>
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<tr>
<td>Wolff # 3</td>
<td>Shut-in</td>
<td></td>
<td>Injector 500</td>
<td>Injector 584</td>
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<tr>
<td>Wolff # 5</td>
<td>Injector</td>
<td>360</td>
<td>Injector 500</td>
<td>Injector 3719</td>
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<tr>
<td>Total water injection</td>
<td></td>
<td>2855</td>
<td>3400</td>
<td>3719</td>
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</table>
Thank You!