Abstract

The Cardium Formation in Alberta, Canada, has produced more than 1.7 billion barrels of light oil since 1953. This zone has been revived as a drilling target since 2008 by application of multi-stage fracture stimulations to horizontal wells. As of November, 2011, 62,000 bopd is being produced from over 1100 horizontal wells. The oil rate in the 3rd month of production (IP3) is used here as a standard to correlate with geologic setting and reservoir properties. The objective is to develop methods to 1) identify where there are recoverable reserves remaining within the boundaries of established pools, including undeveloped tight sands, and 2) high-grade areas outside the known pool boundaries that will produce oil at economic rates from tight sands. The impact on IP3 of differing well-stimulation strategies was not part of this analysis.

The objectives were explored in 2 steps. First, based on where the wells were placed relative to producing areas, over 900 wells having IP3 values were assigned to the following categories: primary recovery area, waterflood area, extensions to known pools, or exploration area. The IP3 data were analyzed by these categories to identify trends and statistics. Observations included:

- average IP3 rates from new wells in and around known pools are higher than average IP3 rates in exploration areas;
- exploration wells accounted for a disproportionate share of poorly performing wells;
- higher gas-oil-ratio (GOR) is associated with lower IP3 rates in every field area.

To address the GOR issue, a screening tool was developed and applied regionally to identify areas where high GOR was expected in oil exploration targets.

Next, an area in Pembina, covering 5 townships, and containing a variety of prospect types was studied. Net pay, oil in-place, oil recovery factor (RF), GOR, and depletion, were quantified in each of 3 zones over the map area: lower sand, main sand and conglomerate. To address exploration risk (i.e., low IP3 rates in exploration wells), multiple regression was used to predict expected IP3 in the tighter halo surrounding the producing area. Net pay in the “main sand” was the most significant variable for prediction of expected IP3. In legacy producing areas,
RF varied from less than 4% to over 16%. A map of RF highlighted areas to be targeted by infill drilling. The approach used here should be applicable to the assessment of the Cardium Formation in other areas.
Production Data From The Cardium Formation Evaluated Within A Geologic Framework To Identify Criteria Useful In Selecting Areas For Exploitation By Multi-stage Fracturing Of Horizontal Wells
Tight Oil in the Cardium Formation

- Highest risk: extension and outpost drilling,
- Real differences in IP across the Cardium tight sand fairway
- Net pay definition: critical to success
- Oil production with high GOR is a significant risk in the Cardium (if you don’t screen for it)
- Relative importance of differing risk factors depends on exploration or development context
THE SUPPORTING STORY

1. Breakdown of production data from horizontals:
   - By exploration and development wells
   - By drilling area
2. Net pay and cutoffs
3. GOR screening
4. Conclusions
Breakdown of Production Data

IP DATA FROM OVER 1000 WELLS
Presenter’s notes: Since 2008, open-hole completions of horizontal wells have given way to cased hole, multi-stage fractured horizontal wells, with great success. Production levels are back up to 1979 levels (30 + years!)
Presenter’s notes: Production rise is poised to go ever steeper. We are awaiting production info on 700+ wells. There are less than 500 wells with 1 year of production.
Median 78 bopd
Average 93 bopd

Presenter’s notes: Histogram of IP 3 month. Lognormal distribution. This is for all IP 3-month data from 1032 wells.
Cumulative Distribution 3 Month IP

- 1032 Cardium Hz Wells
- Median 78 bopd
Presenter’s notes: There are many reasons wells will have low IP: 1) knowingly drill marginal lands (farm-in to earn better lands, drilling on expiring lands, tax treatment for exploration wells, the only land we have on the play) 2) unknowingly drill marginal lands (confidence in high resource estimate misplaced due to anomalous value of key variable) 3) unknowingly drill where significant unknown variables had a negative impact. There are many reasons wells will have high IP: 1) knowingly drill superior wells (competitive advantage from technology or land position) 2) unknowingly drill superior lands (confidence in low resource estimate misplaced due to anomalous value of key variable) 3) unknowingly drill where significant unknown variables had a positive impact.
CLASSIFICATION OF HORIZONTALS
(1032 WELLS ASSIGNED TO CATEGORIES)

Development
- Drilled into primary area
- Drilled into waterflood area
- Drilled into known pool edge

Exploration
- Extension drill (0.5 to 1 mile from known edge)
- Outpost (more than 1 mile)
EXP and DEV Wells Within Groups

- All Hz Wells
- Low IP
- High IP

Exploration
Development

Specific Well Groups
## IP by Development or Exploration Category

<table>
<thead>
<tr>
<th>Location</th>
<th># wells</th>
<th>Avg IP3 bopd</th>
</tr>
</thead>
<tbody>
<tr>
<td>Infill Primary</td>
<td>148</td>
<td>103</td>
</tr>
<tr>
<td>Infill Waterflood (same lsd as injector)</td>
<td>24</td>
<td>66</td>
</tr>
<tr>
<td>Infill Waterflood (adjacent lsd)</td>
<td>79</td>
<td>107</td>
</tr>
<tr>
<td>Edge</td>
<td>177</td>
<td>99</td>
</tr>
<tr>
<td>Extension</td>
<td>296</td>
<td>93</td>
</tr>
<tr>
<td>Outpost</td>
<td>308</td>
<td>85</td>
</tr>
</tbody>
</table>

Red = good, better than average  Blue = bad, worse than average
<table>
<thead>
<tr>
<th>Area</th>
<th>Drills</th>
<th>Avg IP3 bopd</th>
<th>Avg GOR scf/bbl</th>
<th>% Low IP In Area</th>
<th>% High IP In Area</th>
</tr>
</thead>
<tbody>
<tr>
<td>Lochend</td>
<td>34</td>
<td>118.9</td>
<td>1736</td>
<td>21%</td>
<td>32%</td>
</tr>
<tr>
<td>West Pembina</td>
<td>332</td>
<td>114.8</td>
<td>2513</td>
<td>13%</td>
<td>33%</td>
</tr>
<tr>
<td>Willesden Green</td>
<td>79</td>
<td>87.4</td>
<td>7626</td>
<td>13%</td>
<td>18%</td>
</tr>
<tr>
<td>East Pembina</td>
<td>325</td>
<td>85.6</td>
<td>2426</td>
<td>19%</td>
<td>18%</td>
</tr>
<tr>
<td>Garrington</td>
<td>176</td>
<td>81.3</td>
<td>1891</td>
<td>13%</td>
<td>11%</td>
</tr>
<tr>
<td>Ferrier</td>
<td>28</td>
<td>70.1</td>
<td>18517</td>
<td>36%</td>
<td>7%</td>
</tr>
<tr>
<td>Pine Creek</td>
<td>43</td>
<td>62.4</td>
<td>11092</td>
<td>42%</td>
<td>12%</td>
</tr>
<tr>
<td>Wapiti</td>
<td>15</td>
<td>37.9</td>
<td>8411</td>
<td>53%</td>
<td>0%</td>
</tr>
</tbody>
</table>

Red = good, better than average  Blue = bad, worse than average
NET PAY AND CUTOFFS

6% CUTOFF?
Net Pay Example: Keystone Area

- **Oil Well**
- **Gas Well**
- **Horizontal**

6 miles
### AVERAGE POR & PERM: 98 WELLS, KEYSTONE AREA

<table>
<thead>
<tr>
<th>Zone</th>
<th>$k_{\text{max}}$ (mD)</th>
<th>por (frac)</th>
</tr>
</thead>
<tbody>
<tr>
<td>Zone 3</td>
<td>90.7</td>
<td>0.124</td>
</tr>
<tr>
<td>Zone 2</td>
<td>3.6</td>
<td>0.105</td>
</tr>
<tr>
<td>Zone 1</td>
<td>5.0</td>
<td>0.101</td>
</tr>
<tr>
<td>Zone 0</td>
<td>5.2</td>
<td>0.097</td>
</tr>
</tbody>
</table>

Net Pay Using:

- 6% por = 16.1 m
- 20 ohm = 9.4 m

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**Cardium Top**

**Cardium Base**

10-09-49-04W5
Net:Gross Ratio by Porosity Cutoff

9% cutoff = 70% Net:Gross
Verified by tie to Rt logs
20 ohms = 70% Net:Gross

98 wells, 1280m of core
Application: 
Net Pay Zone 2: 
20 ohm cutoff 
C.I.=1 m 
Range: 0 to 9 m 
limits identified
TEST NET PAY CUTOFF AGAINST ACTUAL PRODUCTION FROM HZ WELLS

<table>
<thead>
<tr>
<th></th>
<th>Wells</th>
<th>Avg IP3</th>
<th>Low IP Wells</th>
<th>Risk of Low IP</th>
</tr>
</thead>
<tbody>
<tr>
<td>Pay &gt; 4m</td>
<td>25</td>
<td>98.6</td>
<td>1</td>
<td>4%</td>
</tr>
<tr>
<td>Pay &lt; 4m</td>
<td>26</td>
<td>54.7</td>
<td>11</td>
<td>42%</td>
</tr>
</tbody>
</table>

i) porosity cutoff of 9%
ii) net:gross = 70%
iii) Cutoff resistivity of 20 ohms
minimum pay of 4m at these cutoffs to meet drilling objectives
GOR Screening

MORE THAN JUST CUM GAS PRODUCTION!
GOR Impact on IP3 and Risk

**Avg IP3 bopd**

- **GOR Level**
  - >= 5000
  - < 5000

- **Low IP Group**
- **High IP Group**

**% of Wells With GOR > 5k**

- **Low IP Group**
- **High IP Group**
In General GOR is a Concern When...

<table>
<thead>
<tr>
<th>GOR (scf/bbl)</th>
<th>1st month</th>
<th>3rd month</th>
<th>12th month</th>
</tr>
</thead>
<tbody>
<tr>
<td>&gt; 2500</td>
<td>&gt; 5000</td>
<td>&gt; 7500</td>
<td></td>
</tr>
</tbody>
</table>
Create A Screen to Avoid High GOR

- Oil Well
- Gas Well
- Horizontal

6 miles
Produced 20,800 bbls oil at GOR < 10000. Cum Oil 30,600 bbls

Mappable Variable:
“Low-Gas Oil” = 20,800/30,600 = 0.68
Cycle 0

Cum oil = 35,800 bbl
Low-Gas Oil = 1.0

Cycle 1

Cum oil = 30,600 bbl
Low-Gas Oil = 0.68

Cycle 2

Cum oil = 24,800 bbl
Low-Gas Oil = 0.0
GOR Screen Using “Low-Gas Oil”

- Low-Gas Oil fraction = 1
- Low Gas Oil Fraction = 0
- C.I. = 0.1
Conclusion
Tight Oil in the Cardium Formation

- Definition of net pay in tight sands is a critical factor in drilling success; adapt with new info and technology
- Limits to productive tight sands can be mapped to set boundaries for activity
- Real differences in IP across the Cardium tight sand fairway
- Highest risk: exploration extension and outpost drilling
- Oil production with high GOR is a significant risk in the Cardium (if you don’t screen for it)
- Relative importance of differing risk factors depends on exploration or development context
QUESTIONS
ADDENDUM
Limits of Hz Multi-Stage Completions

What are the limits?

Conventional
Tight
Tight
Tight

Over 1 MM bbls oil
New Hz Drill?

Vertical Dry Hole
New Hz Drill?

02-18-48-08W5

06-23-49-04W5

5m
Presenter’s notes: The Cardium is a “big deal” and has been for “going-on” 60 years.
Presenter’s notes: Conventional: 10’s to 100’s mD, 12% porosity cutoff, sand and conglomerate. Tight: 0.1 to 1 mD, 6% to 9% cutoff, vf sand, silty sand, shaly sand.