Comparing Completions to Geology in the Cardium Formation - North Central Pembina*

Andrew Wiseman¹, Federico Krause¹, and Christopher DeBuhr¹

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Abstract

The Cardium Formation has been the subject of extensive study since Socony Mobil Oil first struck oil in the Pembina area in 1953. Interest in the formation waned during the 1990's; however, with refinements in horizontal drilling and multistage hydraulic fracturing techniques, interest has been rekindled. New drilling targets are thinner, lower quality reservoirs that require a greater understanding of subtle variability of reservoir quality and geometry. We use petrophysical, petrological and production analysis techniques to define a geological framework, characterize the reservoir interval, and examine the effectiveness of different completion techniques. Well logs from over 800 wells and core analyses from 440 wells were used to map the formation and identify conglomeratic intervals. Ten cores were logged to characterize lithofacies. Grain size, XRD, EDX, and CL analyses were conducted on each lithofacies. New and innovative Variable Pressure Environmental Field Emission Microscopy techniques were developed to identify and observe difficult-to-image clays and to conduct rock-fluid interaction experiments. Subsurface mapping revealed that only datums below the sandstones provide a realistic basinward-dipping geometry, and 3 upward-cleaning sandstone clinoforms were identified. The upper clinoforms have their thickest sandstone intervals in more basinward positions than the underlying clinoforms, indicating basinward progradation. Petrological findings include XRD and BSE identification of kaolinite, illite, and mixed layer kaolinite-smectite clays. Quartz overgrowths have been shown to increase grain size and completely occlude porosity within some sandstone-filled burrows. Comparisons between lithofacies and grain-size analyses have revealed a clear inverse relationship to water saturation, such that as grain size increases and shale content decreases, water saturation also decreases. This relationship holds despite the very slight grain-size difference observed between lithofacies.

A total of 126 horizontal wells were used for production analysis. Wells were grouped and compared based on pay thickness, number of fraced stages, and completion fluid. While no positive correlation between pay thickness and production has been observed, there is a strong correlation between completions technology and 1st year production. This is best demonstrated by a 39% increase in 12-month cumulative production in wells with greater than 20 fraced stages.
References Cited


Website

http://www.ags.gov.ab.ca/graphics/atlas/fg23_04.jpg
COMPARING COMPLETIONS TO GEOLOGY IN THE CARDIUM FORMATION - NORTH CENTRAL PEMBINA

Andrew Wiseman
Federico Krause
Christopher DeBuhr
AGENDA

- STUDY AREA INTRODUCTION
  - Importance of Study Area

- GEOLOGY
  - Geological Mapping
  - Porosity/Permeability trends
  - Clay mineralogy
  - Fluid Sensitivity

- PRODUCTION
  - Geology
  - Completions
WHY SHOULD I CARE?

Producing Wells

DATE

мар.00  сент.05  фев.11

мар.00  дек.02  сент.05  июн.08  фев.11  ноя.13

Cumulative bbl

Normalized Months

0  2  4  6  8  10  12

5 m pay

8 m pay

800%

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GEOLOGY
6 Lithofacies Identified

1. Dark Grey Shale & Wacke
LITHOFACIES

6 Lithofacies Identified
1. Dark Grey Shale & Wacke
2. Bioturbated Wacke

Modified from Krause and Nelson, 1984
6 Lithofacies Identified

1. Dark Grey Shale & Wacke
2. Bioturbated Wacke
3. Thinly interbedded VF-grained SS & muds

Modified from Krause and Nelson, 1984
6 Lithofacies Identified

1. Dark Grey Shale & Wacke
2. Bioturbated Wacke
3. Thinly interbedded VF-grained SS & muds
4. Medium to thick-bedded, VF-F-grained SS

Modified from Krause and Nelson, 1984
6 Lithofacies Identified

1. Dark Grey Shale & Wacke
2. Bioturbated Wacke
3. Thinly interbedded VF-grained SS & muds
4. Medium to thick-bedded, VF-F-grained SS
5. Conglomerate

Modified from Krause and Nelson, 1984
LITHOFACIES

6 Lithofacies Identified
1. Dark Grey Shale & Wacke
2. Bioturbated Wacke
3. Thinly interbedded VF-grained SS & muds
4. Medium to thick-bedded, VF-F grained SS
5. Conglomerate
6. Pebbly Mudstone

Modified from Krause and Nelson, 1984
CONVENTIONAL RESERVOIR

6 Lithofacies Identified
1. Dark Grey Shale & Wacke
2. Bioturbated Wacke
3. Thinly interbedded VF grained SS & muds
4. Medium to thick-bedded, VF-F grained SS
5. Conglomerate
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Modified from Krause and Nelson, 1984
6 Lithofacies Identified

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4. Medium to thick-bedded, VF-F grained SS
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Modified from Krause and Nelson, 1984
Max = 17.6 m  Min = 0 m  # of Wells = 1086  W CGL = 277

CONGLOMERATE

Data Points  @  Well locations

max = 17.6 m  min = 0 m  # of Wells = 1086  W CGL = 277

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STRATIGRAPHIC MAP
Russian Marker – Cardium SS

Isopach Thickness (m)
Max = 45 m
Min = 74 m
# of Wells = 458

Data Points

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POROSITY & PERMEABILITY
POROSITY VARIABILITY

LF 2

LF 3

LF 4

Por(%) Min Outlier Max Outlier

LF 2 West

12

0.08

LF 2 East

109

0.10

LF 3 West

28

0.11

LF 3 East

17

0.12

LF 4 West

85

0.12

LF 4 East

34

0.14

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PERMEABILITY VARIABILITY

K_max (md)

<table>
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<tr>
<th>Location</th>
<th>LF 2 West</th>
<th>LF 2 East</th>
<th>LF 3 West</th>
<th>LF 3 East</th>
<th>LF 4 West</th>
<th>LF 4 East</th>
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<tr>
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<td>0.20</td>
<td>0.80</td>
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<td>Max</td>
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<td>27</td>
<td>17</td>
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CLAY MINERALOGY & FLUID SENSITIVITY
Little/no swelling clay

Common swelling clay
PRODUCTION ANALYSES

Base Frac Fluid

Rates

Proppant Tonnage

Wells Orientation

Wells Location

# of Stages

Frac Spacing

Completed Length

Reservoir Pressure

Thickness of Reservoir
- DPSS
- GR
- ILD
- Core Porosity
- Lithofacies

Production data up till Oct 01, 2012

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METHODS

- Production data - geoSCOUT© up to Oct, 2012
- Completions data – Canadian Discovery Well Completions & Frac Database®
- Production averages calculated until well counts dropped below 4
- When well counts were sufficient production was calculated for the 1st 12 months
EAST vs. WEST

West wells outperform east wells
NET-PAY THICKNESS 6% DPSS
NET-PAY THICKNESS

- Thickest pay ≠ best well
- Lower limit of reservoir thickness
Average pay thicknesses are similar

Orientation appears to have little impact on production
Wells with ≥ 20 stages are dramatically outperforming wells with <20 stages.

12 months
19,000 bbl
FRAC SPACING

- Only wells 1200-1800m in length
- Frac spacing below 80 m displays best performance

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Slickwater wells appear to be performing the best.
Slickwater wells are dominantly ≥20 stages
≥20 STAGES vs BASE FLUID

Performance gap disappears

Cumulative Production (bbl)

NORMALIZED MONTHS

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>20 STAGES VS DPSS THICKNESS

Thickest net-pay performs the best

Completions Matter!

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CONCLUSIONS

Geology impacts well performance
CONCLUSIONS

- Geology impacts well performance
- Reservoir properties vary across the study area
- Lithofacies - Por and Perm
CONCLUSIONS

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- Reservoir properties vary across the study area
- Lithofacies – Por Perm
- Clay mineralogy / Fluid Sensitivity
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- Geology impacts well performance
- Reservoir properties vary across the study area
- Lithofacies – Por Perm
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- Lower net-pay limit
CONCLUSIONS

- Geology impacts well performance
- Reservoir properties vary across the study area
- Lithofacies – Por Perm
- Clay mineralogy / Fluid Sensitivity
- Lower net-pay limit
- Density logs are effective when completions are considered
CONCLUSIONS CONT.

Completions impact well performance
CONCLUSIONS CONT.

- Completions impact well performance
- Number of fracced stages appears to have largest impact on wells productivity
- 19,000 bbl
CONCLUSIONS CONT.

- Completions impact well performance
- Number of fraced stages appears to have largest impact on wells productivity
  - 19,000 bbl
- A frac spacing of 80 m or less is optimal
Completions impact well performance
Number of fraced stages appears to have largest impact on wells productivity
19 000 bbl
A frac spacing of 80 m or less is optimal
Well bore orientation has little impact
Completions impact well performance

- Number of frac'd stages appears to have largest impact on wells productivity
  - 19,000 bbl
- A frac spacing of 80 m or less is optimal
- Well bore orientation has little impact
- Slickwater and Water-based fracs are both performing
ACKNOWLEDGMENTS

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- UNIVERSITY OF CALGARY
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- IFFAEM
- TRICAN LABS

Instrumentation Facility for Analytical Electron Microscopy
References


QUESTIONS?
Addendum
Thickest is the best?

Lithofacies Thickness

Resistivity

2 000 bbl
Phih

5 500 bbl
DPSS

5 000 bbl

11 000 bbl

Figure 6: Phi-h quality map showing horizontal wells used for production analysis colored based on Phi-h quality groupings and loca-
Thickeest is the best?

Lithofacies Thickness

- >8 m (20 stages)
- 4-8 m (20 stages)
- >8 m
- 4-8 m

Resistivity

- (≥ 20) >8
- (≥ 20) 4-8
- 6 to 8
- >8

Cumulative Production (bbl) vs. Normalized Months

2 000 bbl

Phih

- > 60
- 30-60
- (≥20) 30-60
- (≥20) > 60

5 000 bbl

DPSS

- (≥ 20) >6
- (≥ 20) 4-6
- >4 < 6
- > 6

5 500 BBL

11 000 bbl

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INTERNAL STRATIGRAPHY
# PAY CUT-OFFS

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<th>Por (%)</th>
<th>K max (md)</th>
<th>SW (%)</th>
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<td>0.08</td>
<td>84</td>
<td>0.11</td>
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<td><strong>6 to 12</strong></td>
<td>0.11</td>
<td>316</td>
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