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Optimizing Completions within the Montney Resource Play
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Introduction

The Montney resource play covers 57,000 square miles from west-central Alberta into northeastern British Columbia. In recent years, the Montney has emerged as one of North America’s top resource plays. Since 2008, there have been more than 3,200 horizontal, multi-stage wells drilled and completed targeting the Montney. As development proceeds, operators are beginning to realize that heterogeneities in the Montney require variable approaches to completions to achieve optimal results within each region of the play.

In the vast majority of resource plays, the initial production rate (IP) is a key proxy in the estimated ultimate recovery (EUR) and, therefore, forecasting the economics of individual wells. Using the optimum completion design is critical for getting the optimal IP and economics, particularly in a stressed pricing environment.

Analytics

The Montney is a geographically-extensive reservoir composed of several sedimentary facies in which inhabit various temperature ranges and hydrodynamic systems. The reservoirs types range from shoreface, coquina, storm-dominated shoreface, and proximal through distal turbidite channel and fan complexes.

In 2013, Canadian Discovery Ltd. (CDL) completed the “Gas Liquids and Light Oil Fairways” regional study within the Western Canada Sedimentary Basin. The aim of this study was to characterize liquids-rich gas trends across 24 geological intervals in Alberta and British Columbia, including the Montney. Over 530,000 gas analyses and 250,000 oil analyses were used to map liquid trends. It was observed that the gas-liquids concentrations followed discrete and narrow trends. The controlling factors for these trends were determined to be: formation temperature, pressure and facies.

Applying this methodology to the Montney, CDL has identified 21 distinct play areas. Wells within each of these play areas share similar “DNA”, as they will produce from similar pressure regimes, reservoir facies and geothermic conditions. In order to optimize completions in the Montney, operators need to be aware of the pressure, temperature and facies controls within their operational areas. The methodology for determining each of the controlling factors will be briefly described here along with regional maps showing the present day isotherms, pressure systems and depositional facies of the Montney.
Geothermics:

Geothermal gradient (GTG) values were created with data from pool reserves reports and production tests, using the following calculation:

\[
\text{Temp Grad} = \frac{[\text{Fm Temp} - \text{Surf Temp}] \times 1000}{\text{Fm Temp Depth}}
\]

The surface temperature was set at 5°C, based on published guidelines (e.g., Bachu S. and Burwash R.A., 1994), the data were further vetted to identify and remove anomalous data points. Isotherms contours were then created by multiplying the grid files for the GTG and the True Vertical Depth to the top of the Montney.

Wet gas indices for C₂⁺ to C₅⁺, and Shallow- and Deep-Cut Yields shows strong relationship between current day formation temperature and reservoir phase relationship, validating the use of reservoir temperature as an indicator for the thermal maturation of the Montney to determine the expected phase or fluid type (Table 1.1) for each play area. Note the influence of the Dawson Creek – Fort St John Graben Complex on the isotherms, pulling sharply westward.

<table>
<thead>
<tr>
<th>Temperature Class (°C)</th>
<th>Dominant Phase</th>
</tr>
</thead>
<tbody>
<tr>
<td>&gt;100</td>
<td>Dry Gas</td>
</tr>
<tr>
<td>80 - 100</td>
<td>Liquids-Rich Gas &amp; Condensate</td>
</tr>
<tr>
<td>60 - 80</td>
<td>Liquids-Rich Gas</td>
</tr>
<tr>
<td>&lt;60</td>
<td>Oil</td>
</tr>
</tbody>
</table>

Table 1.1
A regional map of the Montney showing the 60°C, 80°C and 100°C isotherms overlain on the C₅⁺ Deep-Cut Yield shows the relationship between present day temperature and gas-liquids content. Figs 1 and 2.
Hydrodynamics:

Reservoir pressure data from DST and AOF Data were used to develop Pressure vs. Elevation graphs (P/E), and Pressure vs. Depth Ratio (P/D) Maps to show distribution of Deep Basin and Aquifer fairways. Hydrocarbon plays within the Montney Formation can be divided into two main categories: The unconventional Montney Regionally-Continuous Gas System (RCGS), which is a “Deep Basin-type” mega gas pool, and the conventional Montney Aquifer.

The Montney RCGS occurs mainly within the tight Montney siltstones associated with the offshore-to-distal offshore facies and the distal turbidite facies. Gas is not static in the RCGS, but is dynamic and flows through the tight reservoir. This flow is the result of the large variation in pressure within the RCGS, and permeability differences between and within Montney facies can impede or focus this flow leading to even larger pressure variations. The overpressured portion of the RCGS occurs mainly within the tight Montney siltstones associated with the offshore-to-distal offshore facies and the downdip part of the storm-dominated shoreface offshore transition facies. The RCGS does include portions of the more permeable reservoirs in the shoreface and storm-dominated shoreface facies of the Montney; however, the pools in these facies are generally underpressured. Differences in permeability between the various Montney facies serve to impede and focus the gas flow complicating the flow pattern and adding to the multiplicity of gas columns that characterize the gas pools in the overpressured Montney.

The Montney Aquifer lies mainly within the Montney siltstones to very fine-grained sandstones of the storm-dominated to shoreface-associated facies. Oil and gas pools found in the aquifer are contained within conventional structural and stratigraphic traps, and are normally-pressured to underpressured, and have downdip water contacts, relative to the regional hydrostatic gradient. Complex facies distributions within the Montney aquifer may create large extensions for some of these conventional pools.

Based on Deep Basin or Aquifer categories and pressure values, the Montney can be divided into six different pressure classes (fig 3 and table 1.2).

<table>
<thead>
<tr>
<th>Pressure Class</th>
<th>Values (kPa/m)</th>
<th>Description</th>
</tr>
</thead>
<tbody>
<tr>
<td>1</td>
<td>&gt;12</td>
<td>Deep Basin</td>
</tr>
<tr>
<td>2</td>
<td>10-12</td>
<td></td>
</tr>
<tr>
<td>3</td>
<td>8-10</td>
<td>deep basin</td>
</tr>
<tr>
<td>4</td>
<td>&lt;8</td>
<td>deep basin</td>
</tr>
<tr>
<td>5</td>
<td>8-10</td>
<td>aquifer</td>
</tr>
<tr>
<td>6</td>
<td>&lt;8</td>
<td>aquifer</td>
</tr>
</tbody>
</table>

Table 1.2
Facies:

The Lower Triassic Montney Formation records deposition in a structurally active, mid-latitudinal west-facing continental margin/pull apart basin influenced by prevailing easterly winds and storm-dominated shoreface conditions. The product of these paleogeographic and structural conditions is a complex siliciclastic and locally carbonate reservoir system that is dominated by relatively well-sorted dolomitic siltstones (rarely shales) and very fine-grained sandstones (probably of aeolian provenance). The clastic reservoirs occur in a range of shoreface, coquina, storm-dominated shoreface, and proximal through distal turbidite channel and fan complexes.

Figure 4

Based on the work of Graham Davies, there are four key facies fairways in the Montney, as shown in the table and facies distribution map below (Fig 5 & Table 1.3):

<table>
<thead>
<tr>
<th>Facies Class</th>
<th>Relative Permeability</th>
</tr>
</thead>
<tbody>
<tr>
<td>1 Shoreface</td>
<td>good</td>
</tr>
<tr>
<td>2 Coquina</td>
<td>excellent</td>
</tr>
<tr>
<td>3 Storm-dominated Shoreface</td>
<td>ok to good</td>
</tr>
<tr>
<td>4 Distal Facies</td>
<td>poor</td>
</tr>
</tbody>
</table>

Table 1.3
Productivity in the various facies is controlled by Darcy’s Law, in which permeability and pressure are key determining factors in well productivity. As previously noted, the large variation in pressure within the RCGS can be related to the permeability differences between and within Montney facies.

The authors have selected three resource play areas (Stoddart–Boucher, Tupper and Kaybob South) using the interaction of Pressure-Temperature-Facies (P-T-F) Fairways to investigate:

- different completions methods being employed in these areas,
- determine the impact of P-T-F on completions design and production, and
- establish which completion design(s) may be optimal for each of the selected Montney Play Areas (Fig 6).

A brief description of the P-T-F for each of the selected Play Areas is provided below.

Figure 6:

Stoddart-Boucher Area – Liquids

The Stoddart-Boucher play area is a Distal Shelf Liquids Play, which is heavily influenced by the Dawson Creek – Fort St. John Graben Complex, and is not at or immediately adjacent to the regional subcrop unconformity. Production from the Stoddart-Boucher play area is predominantly liquids rich gas, with oil reservoirs occurring within the lower Montney. The oil play is poorly-developed, but is deemed to have good potential due to the high probability of lower permeability oil zones that have historically
been overlooked or bypassed in vertical wells. The oil reservoirs are sometimes developed within the turbidite/submarine fan zone near the base of the Montney, but may also be found within the middle Montney.

Stoddart-Boucher play area is in the overpressured Deep Basin with pressure values exceeding 12 kPa/m, but within the <60°C isotherm, which indicates that the play area will be an overpressured liquids play with generally poor reservoir characteristics.

The completions data for plug and perf, slickwater fracs shows that there is a strong correlation between lateral length and gas rate, figures 7 and 8. Operators have recognized this, as lateral lengths have increased over time. Frac spacing has settled into a well-defined range, between 150m and 250m, figures 9 and 10. There does not appear to be relationship between spacing and production rate. Slurry density has decreased over time, figures 11 and 12, and are negatively correlated with gas rate. Operators appear to have found that a slurry density of approximately 100kg/m3 is optimal for the area. That the slurry density exhibits this correlation is interesting as the amount of fluid per stage, figures 13 and 14, and proppant per stage, figures 15 and 16, do not show correlation to production rates.
The completions data for ball and seat, slickwater fracs shows a similar strong correlation between lateral length and gas rate, figures 17 and 18. For this completion type the frac spacing is tightly clustered around 100m, figures 19 and 20. Production rate appears to be mildly correlated to slurry density, figures 21 and 22. Fluid per stage, figures 23 and 24, and proppant per stage, figures 25 and 26, show a weak, positive correlation with production rate.
Figure 17: Lateral Length vs IP Gas

Figure 18: Lateral Length vs 6 mo Gas Rate

Figure 19: Frac Spacing vs IP Gas

Figure 20: Frac Spacing vs 6 mo Gas Rate

Figure 21: Slurry Density vs IP Gas

Figure 22: Slurry Density vs 6 mo Gas Rate

Figure 23: Fluid per Stage vs IP Gas

Figure 24: Fluid per Stage vs 6 mo Gas Rate
Figure 25: Proppant per Stage vs IP Gas

Figure 26: Proppant per Stage vs 6 mo Gas Rate

Slickwater is the dominant completion fluid, for the Stoddart-Boucher area. The completion technology was primarily plug & perf in the early years, this has shifted to ball & seat in the past two years. Figures 27 and 28 show that slickwater, plug & perf and slickwater, ball & seat completions deliver nearly identical results. Both of these completion styles outperform water, plug & perf completions. With nearly identical results for the slickwater completions, the shift to ball & seat would suggest that this is a cost based decision by the operators. With nearly identical results, this would suggest that the shift to ball & seat is a cost based decision of the operators.

Figure 27: IP Gas Cumulative Probability

Figure 28: 6mo Cum Gas Cumulative Probability

Kaybob South Area – Liquids

The Kaybob South play area is a Shoreface, Oil to Condensate Play, which lies in the southeastern region of the Montney. The play is well-developed with approximately 200 horizontal, multi-stage completions in the Montney.

The Kaybob South reservoir is composed of “coarse” silts and fine-grained sandstones, which lie in the 8 – 10 kPa/m aquifer system, and have reservoir temperatures of 60°C – 80°C, which indicate a normally-pressured, liquids-rich gas play with good reservoir characteristics.

The dominant completion technology in this area is ball and seat. There appears to be a mild correlation between lateral length and production rate, figures 29 and 30. Lateral lengths are clustered in two groups, the largest in a range between 1,400 and 1,600m and a second group in a range between 1,900m and 2,000m. Frac spacing is typically between 70m and 75m, figures 31 and 32, and the number
of frac stages per well ranges from 12 to 32 with most wells seeing between 21 to 23 stages, figures 33 and 34. Proppant per stage is exclusively around 10 tonnes per stage, figures 35 and 36.
For the area it is clear that the completion fluid that delivers the best results is oil. Figures 37 and 38 show that oil and oil charged with N2 give consistently better results that water and water/surfactant completion fluids.

Tupper Area – Dry Gas

The Tupper area is in the Distal Montney facies, with a high temperature, over pressured, Deep Basin setting which is prone to dry gas. The Distal Gas Play focuses on gas zones scattered throughout the entire Montney section. Reservoirs are found in turbidites and submarine fans of the lower Montney, as well as coarser-grained zones in the middle and upper Montney. Gas is the dominant phase in throughout the Montney section and can be exploited through horizontal drilling and multi-stage fracturing. The play lies west of the subcrop margin, and extends over a large area paralleling the Disturbed Belt.

The Tupper Play Area lies within the RCGS of the Deep Basin Montney and has pressure values of >12 kPa/m and has reservoir temperatures of greater than 100°C, indicating a dry gas play with poor reservoir characteristics.

There are relatively fewer completions in this area compared to the Kaybob South and Boucher. This is likely driven by the economics of dry gas production. The completions in this play area are split between ball and seat and plug and perf technology, using slickwater. The well configuration typically has long laterals, figures 32 and 33, and the number of frac stages ranges from between 6 and 18, figures 34 and 35. The performance of the ball and seat completions is slightly better than the plug and perf, figures 36 and 37.
Conclusions:

As the authors expected, there is no one optimal completion type for the Montney Resource Play, but as we investigated the completion types being used in the Stoddart-Boucher, Kaybob South and Tupper areas, we did see very different completion programs being used in the different areas. The influence of Pressure-Temperature-Facies controls did not seem to be a strong factor in the selection of the different completions technologies in the three resource play areas that we investigated, but it did seem to be a factor in base fluid selection.

In the Kaybob South play, a normally pressured, aquifer system with good reservoir quality, the preferred base fluids were Oil and N2 energized Oil, both of which demonstrated better production rates than other base fluid types, regardless of the completion technologies being employed.
The Tupper and Stoddart-Boucher resource play areas are over pressured, deep basin systems with poorer reservoir characteristics. Again we see little variation in the performance of the wells when looking at different completions types, but slickwater fluid systems generally outperformed water fracs, again independent of the completion technologies being employed.

What was, somewhat, surprising to the authors was the lack of experimentation in completion types within each of the areas that we looked at. The horizontal multi-stage completion designs in all three of the resource play areas have remained much the same from the initial wells to current completions. The well bores are typically longer with more stages, but the stage lengths, proppant and fluid volumes have remained much the same in each of the areas. Even where there has been a transition to open hole completions from the earlier plug & perf systems in the Stoddart-Boucher play area, the rest of the ‘recipe’ has remained static, with similar stage lengths and Proppant and fluid volumes, and fluid type.

The influence of the Pressure-Temperature-Facies controls within the Montney on horizontal, multi-stage completions appear to be an important consideration for completions design for the different play areas, but within each play area, the operators appear to be reluctant to experiment with the frac design beyond the completed length and number of stages.

References

WCSB Gas Liquids & Light Oil Fairways Study, 2013, Canadian Discovery Ltd.
Well Completions & Frac Database, Canadian Discovery Ltd.