Optimizing Drilling & Completions Performance in Liquids Rich Unconventional Plays
Important notice

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Outline

1. Steps in unconventional resource play development

2. The Montney – a premiere North American unconventional resource

3. The importance of drilling and completion optimization in the commercialization of unconventional resources

4. Drilling and completion optimization
   i. What has already been done?
   ii. What are the results?
   iii. Where do we go from here?

5. Summary and conclusions
There are many steps involved in bringing an unconventional resource play to the commercial development stage.

Drilling and completions optimization comes to the fore in steps #4 and #5, in the process illustrated at left.
The Montney – one of the premiere unconventional plays in N. America

- The Montney is increasingly being recognized as one of the premiere unconventional resource plays
- Parts of the Montney have among the highest liquids yields, and best economics in N. America
- Recent forecasts* indicate that the Montney will be one of the dominant producers in the WCSB, going forward

Montney commercial development

- The Montney will be developed in multiple layers
- In many areas, commercial development will require > 10 wells/section*
- Applying this estimate to 18 of the largest Montney acreage holders, and assuming that 50% of their acreage is developed at this density over a 25 year period, yields an estimated drilling requirement of 1,800 wells per year (45,000 wells in total)
- Even assuming $6MM/well (conservative, depending on location), this comes to >$10B/year

Drilling & completion optimization is a major focus in the Montney

- Considering the magnitude of the capital required, it is no surprise that drilling and completion optimization is a major focus for Montney operators.
Why is drilling & completions optimization critical?

Impact on Well Economics

- The importance of drilling & completion optimization can be demonstrated by comparing the relative number of wells with < 1 year payout, under the various scenarios shown.

- 33% cost reduction & 25% production performance improvement are equivalent; both result in ~140% increase in wells meeting the example economic criteria.

- Combined 33% cost reduction and 25% production performance improvement results in ~230% increase in number of wells meeting the economic criteria.

Adapted from Seven Generations
Drilling optimization
Montney drilling cost performance

Figures shown are based on field estimates & are subject to revision. Results shown are in order of rig release date.

- Comparing the last wells to the first well; reductions of ~36% have already been achieved, on a $/m lateral basis
- There is still much more room to improve

### TESTED; IN USE GO FORWARD
- Managed pressure drilling
- Computerized torque control
- Computerized tool face control
- Large drill pipe
- Aggressive build rates
- Hybrid/modified bit selection for build
- Custom bits for lateral

### TESTED; NOT IN USE GO FORWARD
- Rotary steerable
- Wellbore strengthening
- Monobore
- Downhole sensors/data gathering
- Brine mud system
- Underbalanced drilling with N2
- Continuous circulation

Adapted from Seven Generations
Drilling results – surface, intermediate, build & lateral

Adapted from Seven Generations
Putting it all together – what is already achievable?

- Overall drilling days have shown continuous improvement over time.
- The “combined bests” illustrates what is achievable with consistently good performance across all sections of the well.
- This can also be compared to technical limit, and theoretical limit performance.
Drilling cost efficiencies of extended laterals

- Extending the combined bests model indicates significant cost efficiencies with longer laterals.
- For example, extending a 1500 m lateral to 3000 m would result in a 30% decrease in drill time per metre of lateral (based on the model shown).
Drilling – What has been tested?

- Bifuel (natural gas/diesel) on rigs & boilers
- Premium spec casing; reduced probability of failures
- Mud systems
  - Invert
  - Water/brine
  - Managed pressure drilling (MPD)
  - Underbalanced drilling (UBD) with N2 currently being tested
- Downhole tools
  - Larger drill pipe
  - Custom bit design/specialized/hybrid bits
  - Rotary steerable systems
  - Downhole data gathering systems
- Automation
  - Computerized stick slip control
  - Automated tool face control
- Well design
  - Pad drilling to reduce move and lease construction costs
  - Optimized build rates
  - Longer laterals
- Multiple well pads

Adapted from Seven Generations
Montney drilling cost performance

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- There is still much more room to improve.

Figures shown are based on field estimates & are subject to revision. Results shown are in order of rig release date.
Drilling technology test summary

<table>
<thead>
<tr>
<th>Well Section</th>
<th>Technologies/Approaches</th>
<th>Drilling Days</th>
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</thead>
<tbody>
<tr>
<td>Surface hole</td>
<td>1. Larger drill pipe</td>
<td>1.6</td>
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<tr>
<td></td>
<td>2. Computerized stick slip mitigation</td>
<td>1.2</td>
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<td></td>
<td>3. Automated tool face control</td>
<td>0.4</td>
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<tr>
<td>Intermediate section</td>
<td>1. Monobore well design</td>
<td>9.0</td>
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<tr>
<td></td>
<td>2. Computerized stick slip mitigation</td>
<td>5.6</td>
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<tr>
<td></td>
<td>3. Automated tool face control</td>
<td>3.4</td>
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<tr>
<td>Build section</td>
<td>1. Aggressive build rates (10-12 deg/30m)</td>
<td>9.0</td>
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<tr>
<td></td>
<td>2. Specialized/hybrid bits</td>
<td>3.7</td>
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<td></td>
<td>3. Managed pressure drilling</td>
<td>5.3</td>
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<tr>
<td>Lateral (2300 m comparison)</td>
<td>1. Larger drill pipe</td>
<td>32.0</td>
</tr>
<tr>
<td></td>
<td>2. Computerized stick slip mitigation</td>
<td>12.5</td>
</tr>
<tr>
<td></td>
<td>3. Managed pressure and under balance drilling</td>
<td>19.5</td>
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<tr>
<td></td>
<td>4. Managed pressure and under balance drilling</td>
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<tr>
<td></td>
<td>5. Specialized brine (Reduced torque and drag)</td>
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<td></td>
<td>6. Reduced geosteering</td>
<td></td>
</tr>
<tr>
<td></td>
<td>7. Extended reach (3000 m)</td>
<td></td>
</tr>
<tr>
<td></td>
<td>1. Rotary steerable</td>
<td></td>
</tr>
<tr>
<td></td>
<td>2. Normal brine systems</td>
<td></td>
</tr>
<tr>
<td>Other</td>
<td>1. Natural gas fuel</td>
<td></td>
</tr>
<tr>
<td></td>
<td>2. Pad drilling</td>
<td></td>
</tr>
<tr>
<td>TOTAL</td>
<td></td>
<td>51.6</td>
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<td></td>
<td></td>
<td>23.0</td>
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<tr>
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<td></td>
<td>28.6</td>
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</tbody>
</table>

- Significant improvements have been made to date, but there is still room for more
- As technologies are improved/developed, the approach will continue to evolve
- Pad drilling & lease construction activities also save time and money; these savings are additional to the drilling day savings shown

Adapted from Seven Generations
Drilling optimization – where do we go from here?

- The graph, at left, illustrates the high-level breakdown of times for a composite example Montney horizontal well in the Kakwa area.
Let’s have a closer look

• High frequency digital data (up to 1/second) offers the opportunity to go from the macro, to the micro, when analyzing drilling performance.
Further breakdown of the drilling segment

- Drill: 68%
- Identified lost time: 14%
- Casing & liner installs: 18%
- Drill circ, ream/wash: 4%
- Drill connections: 7%
- Trips: 20%
- Drill rotary: 28%
- Drill sliding: 10%
Having a closer look – connections while drilling

Example connection #1

Example connection #2

12 minutes; drill to drill

22 minutes; drill to drill
Having a closer look – connections while tripping

By comparing:
- Event to event
- Crew to crew
- Rig to rig
- Area to area ...

We can:
- Identify best practices
- Streamline procedures
- Standardize operations
- Identify technology upgrade requirements
## Drilling optimization – how far might we go?

<table>
<thead>
<tr>
<th>Segment</th>
<th>Sample Well %</th>
<th>Possible Improvements</th>
<th>Estimated Potential Savings (%)</th>
</tr>
</thead>
<tbody>
<tr>
<td>Drilling rotary</td>
<td>28</td>
<td>Improved bit design/selection</td>
<td>19</td>
</tr>
<tr>
<td></td>
<td></td>
<td>Precise bit wear analysis &amp; improved drilling performance simulation</td>
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<td></td>
<td></td>
<td>Underbalanced drilling with natural gas</td>
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<tr>
<td>Slide drilling</td>
<td>10</td>
<td>Higher build rates to reduce length of build section</td>
<td>6</td>
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<tr>
<td></td>
<td></td>
<td>Improved rotary steerable</td>
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<td></td>
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<td>Automated steering</td>
<td></td>
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<tr>
<td>Tripping</td>
<td>20</td>
<td>Improved bit design/selection</td>
<td>13</td>
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<td></td>
<td></td>
<td>Automated stick slip mitigation</td>
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<td></td>
<td></td>
<td>Continuous circulation to reduce connection times</td>
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<td></td>
<td></td>
<td>Precise bit wear analysis &amp; improved drilling performance simulation</td>
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<td>Higher reliability BHA’s</td>
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<td>Increased drilling automation</td>
<td></td>
</tr>
<tr>
<td>Drilling connections</td>
<td>7</td>
<td>Continuous circulation to reduce solids removal issues</td>
<td>5</td>
</tr>
<tr>
<td>Circulating, reaming, etc.</td>
<td>3</td>
<td>Continuous circulation to reduce solids removal issues</td>
<td>4</td>
</tr>
<tr>
<td>Casing &amp; liner installs</td>
<td>18</td>
<td>Open hole completions; eliminate production liner</td>
<td>5</td>
</tr>
<tr>
<td>Identified lost time</td>
<td>14</td>
<td>Real time operating centres</td>
<td>14</td>
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<tr>
<td></td>
<td></td>
<td>Automated rig activity detection (ARAD) &amp; analysis</td>
<td></td>
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<tr>
<td></td>
<td></td>
<td>Increased drilling automation</td>
<td></td>
</tr>
<tr>
<td>TOTAL</td>
<td>100</td>
<td></td>
<td>67</td>
</tr>
</tbody>
</table>

### Other

| Hidden lost time                        | Automated rig activity detection (ARAD) & analysis | 15 (?) |
| Other efficiency measures               | Pad drilling                                       |       |
|                                         | Walking rigs                                       |       |
|                                         | Batch drilling                                     |       |
|                                         | Multilateral drilling                              |       |
|                                         | Large scale program efficiencies                   |       |
|                                         | 100% natural gas fuel                              |       |
Completion optimization
Montney completion cost performance

Comparing the last wells to the first well, significant reductions have been demonstrated, on a $/tonne basis.

In contrast to drilling, completion performance must be measured by value:
- Production
- Recovery
- Cost
- Drainage volume/well spacing

As a result, there is a time lag involved.

Based on field estimates

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Based on field estimates
Completion cost efficiencies of extended laterals

Completion costs can be modelled as roughly a function of proppant tonnage; all other factors being equal.

Based on this model, increasing lateral length from 1500 m to 3000 m results in a 33% reduction in cost/m lateral, assuming 1.0 tonne proppant/m lateral.
Completions – what has been tested?

- **Frac Fluids**
  - Slick water
  - N2 foam based fluid
  - Water based gels

- **Lateral wellbore spacing**
  - 160 to 400m (4 wells to 10 wells/section; 160 to 64 acre spacing)

- **Frac spacing**
  - 70 to 120 m (230 ft to 394 ft)

- **Proppant loading**
  - 0.5 to 2.1 tonne/m (335 to 1408 lb/ft)

- **Proppant types**
  - Normal sand, through high strength ceramics
  - Various combinations of sizes

- **Well design**
  - 4 ½” and 5 ½” liners
  - Open hole packers, with various types of ball drop systems, and plug & perf

- **Production strategy**
  - Aggressive vs more conservative flowbacks after fracturing
  - Gas lift and jet pump artificial lift systems

Adapted from Seven Generations
Experience to date has tended to indicate that larger fracs perform better.

As a test, two isolated wells were drilled from the same pad, in opposite directions - one well was frac’d with 0.67 tonne/m lateral, and the other was frac’d with 1.32 tonne/m lateral.
Early production data indicated that the well with the larger frac had performed significantly better than the other well, in terms of both wellhead liquids and value-based BOE (20:1).

More work (continued monitoring, more testing, economic analysis) will have to be done to determine the optimum frac size.

The determination of optimum frac size will also, in all likelihood, be affected by the choices made on lateral spacing.

Based on field wellhead estimates.
Pad 8 – 320 m & 400 m (128 & 160 acre) spacing test

- At Pad 8, a 4 well spacing test was drilled, in the opposite direction to an existing isolated well

- Wells were drilled with 320m (5 wells per section) and 400m (4 wells per section) spacing

- The parameters that were different between the single well and the spacing test wells:
  - Spacing/bounding by other wells
  - Frac size – the spacing test wells had larger fracs
  - Flowback choking – the spacing test wells were produced with lower drawdown

Adapted from Seven Generations
Pressure responses at Pad 8

- Pressure response observed at Well #1 (from toe port) due to fracing initial few stages at Wells #2 and #3.
- Tracer data confirms communication between Well #2, stages 1-3, to Well #1.
- Tracer data also suggests Well #2, Stages 4 – 11 are at least partially communicating with Well #1.
- All remaining fracs (78) placed in relative isolation (i.e., no observed communication with offset wells).
- Considering relatively minor communication associated with ~120 tonne hydraulic fractures (average of 1.5 tonne/m), inter-well spacing of 320m (5 wells/section) is likely too widely spaced for maximum recovery or value.

Adapted from Seven Generations
Higher concentration tracer, observed in Well #1 (4-9-64-4W6) originating from frac stages 1 – 6 in Well #2 (1-8-614-4W6) and, to much lesser extent, from frac stages 7-11.
Pad 8 spacing test production – wellhead liquids & BOE (20:1)

- On a wellhead liquids and BOE (20:1)* basis, all four spacing test wells out-performed the single well after ~60 days of production

- One of the two best wells was an outside well, and the other is a bounded well

- The longer term remains to be seen, but early results would tend to indicate that wells could be drilled closer than 320 m

- It is important to note that the fracs were 50% larger on the four spacing test wells than the fracs on the single well

* Based on field wellhead estimates

Adapted from Seven Generations
Pad 19 - 160m (64 acre) spacing test

- At Pad 19, a 2 well spacing test was drilled, in the opposite direction to an existing isolated well
- Wells were drilled with 160m (10 wells per section) spacing
- Drilling and frac parameters were held the same (as closely as possible)
Pad 19; 160m (64 acre) spacing test – fluid tracer results

Tracer results indicate:
- Good response along the wellbore of the traced well; 14-17
- Strong showing of all tracers (except section 5) in the offset well; 02/14-17

Overall, there appears to be strong fluid communication between the traced well and the offset well

Adapted from Seven Generations
The overlay of early production rate and pressure data from the two spacing test wells indicate a pressure “interference” resulting from production in the other well.

Although the impact is difficult to quantify, especially given the fact that this data is very early time in the lives of these wells, the levelling off of the pressure response in the well in black during continued production from the well in red, was encouraging.

Based on field wellhead estimates

Adapted from Seven Generations
One of the 160m spacing test wells had out-performed the single well by 100 days on both a wellhead liquids and BOE (20:1) basis.

The second spacing test well had a very similar cumulative production profile, albeit at somewhat lower flowing pressures.

More work (continued monitoring, more testing, economic analysis) will have to be done to determine the optimum spacing.

The determination of optimum spacing will also, in all likelihood, be affected by the choices made on frac size.
Completions – where do we go from here?

• **Continued testing to determine:**
  • Optimum spacing between laterals (how many wells/section)
  • Optimum proppant loading (how many tonnes/m lateral)
  • Optimum frac spacing (metres between frac stages)
  • Optimum fluid design (water vs foam vs hydrocarbon, etc.)
  • Optimum production strategy (aggressive drawdown vs slowback)

• **Fresh water use will become a make or break issue**
  • Water recycling (not a complete solution) and/or,
  • Saline water-based fluid systems and/or;
  • Hydrocarbon-based fluid systems

  **must be advanced to allow the industry to function, going forward**

• 100% natural gas-fuelled equipment
• Efficient completion systems for longer laterals
• More and more industry discussion about refracs
  • Existing systems do not accommodate this well
• **Ultimately, the answer may well be open hole completions in the Montney**
  • Systems to deliver this are already under development (these systems could also reduce drilling costs, as previously discussed)
Summary and conclusions

• Montney operators are very focused on drilling and completion optimization

• Good progress has already been made, but there is still a lot of room for improvement

• Areas to build on that are common to drilling and completions
  • Pad development
  • Batch operations
  • Increased reliability of downhole equipment
  • Expanded use of natural gas fuel (ultimately 100%)
  • Reduced fresh water use, particularly in completions (ultimately none)
  • Increased use of real time centres for operations management

• Step changes anticipated:
  • Underbalanced drilling with natural gas
  • Increased use of automated rig activity detection and analysis to eliminate hidden lost time
  • Precise bit wear analysis and improved drill bit performance modelling
  • Continuous circulation drilling to reduce time spent on solids removal
  • Open hole completions (affects both drilling and completions)
  • Increased automation in both drilling and completions operations (ultimately autonomous?)
QUESTIONS?

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