HYDRAULIC FRACTURE WATER USAGE IN NORTHEAST BRITISH COLUMBIA: LOCATIONS, VOLUMES AND TRENDS

Elizabeth G. Johnson[1] and Laura A. Johnson[2]

ABSTRACT

Water demand for gas development in northeast British Columbia is dictated by certain aspects of multistage hydraulic fracturing. Approximately 500 wells, dating from 2005 to 2010, each with more than three fracture stages, were analyzed in terms of water use and gas production. Special focus was placed on fracture type, stimulation volume, well location and number of fractures per well. The water volume per fracture stage can vary by an order of magnitude depending on the completion method used. Water use is amplified by the number of completions per well. Slickwater completions are a preferred method because of their low cost and their ability to generate high stimulated reservoir volumes. The completion method and (to a lesser extent) the number of completions per well, is dictated by the geology of the basin. Gas production in the Montney Trend is very economical is terms of water use compared to the Horn River Basin. Water demand is expected to be high in the Cordova Embayment and the Montney North Trend. As water use is increasing rapidly, ongoing monitoring and improved database access are recommended for the Horn River Basin, the Montney North Trend, the Cordova Embayment and the Liard Basin.

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INTRODUCTION

Predicting potential water demand for gas development in northeast British Columbia is necessary for water management. One of the British Columbia Ministry of Energy and Mines' goals is to facilitate industry's needs for water and to share information on water use with other ministries and stakeholder groups, including the Ministry of Environment; the Ministry of Forests, Lands and Natural Resource Operations; the British Columbia Oil and Gas Commission (OGC); the Canadian Association Petroleum Producers and communities. Access to water is a requirement for sustaining industry growth. Accordingly, anticipation of potential water demand is critical to the Ministry of Energy and Mines' mandate.

Predictions for water use are based on trends in well development and the specific multistage hydraulic fracturing approach being used. To date, most of the assumptions made on industry-required water volumes and the rate of usage in British Columbia has been based on reports from industry operations in two areas of the province: the Montney Trend and the Horn River Basin (HRB). The volume of water used by the oil and gas industry in northeast British Columbia varies widely from less than 1000 m^3 to more than 70 000 m^3 per well (Kennedy, 2011). It is important to establish the extent to which estimates for water use in one play are a meaningful proxy for industry-related water use in other areas.

The purpose of this report is to gain an understanding on the aspects of multistage hydraulic fracturing that most affect water consumption and the location and extent to which they are being employed. Specifically, information is sought on the choice of completion method, the number of fracture stages per well, the horizontal length of the wells that is fractured and anticipated water returns for multistage fracture wells in the province. This information is important because it may provide insight into whether or not significant differences in water-use volumes exist between the province's major gas plays, and guidance on future efforts to predict industry-related water demand. The scope of the project is limited to wells with multiple hydraulic fracturing stages.

BACKGROUND

Multistage hydraulic fracturing

Hydraulic fracturing (known as 'fraccing', 'frac'ing' or 'fracking') is the process of creating a fracture in rock using pressurized fluid. It is primarily used in petroleum development to increase well production. Fractures create free space in a rock mass for oil or gas to move easily from the rock matrix to the wellbore and up to surface. Because the high-pressure environment of the rock formation naturally causes a fracture to close, the fracture is propped open with sand or ceramic grains (proppant). The open fracture allows gas and fluid to flow through to the wellbore. Wellbores may have a vertical, horizontal or directional orientation and the process can occur at any specific location along the wellbore, but is more commonly implemented at multiple locations along a horizontal wellbore section. Water use per well is determined by the type of stimulation treatment employed and is amplified by the number of completions per well.

Two methods of generating multiple fractures along a wellbore are commonly used in northeast British Columbia: plug and perf (PnP) and open hole multistage systems (OHMS; Kimmitt, 2011). The PnP method cements the production casing (or liner) in the horizontal wellbore and then punctures the casing at select locations to create fractures. Fracturing is initiated from the wellbore in stages (hence the term 'multistage') and after each stage is fractured (known as a 'completion'), a plug is set to seal off that zone. All of the plugs are drilled out afterwards. The OHMS method (also called the ball-drop system) leaves the production zone open (without casing) and uses a tool to mechanically create access points for fracturing between packers. The packers are automated and do not have to be drilled out. The method of stimulation, in part, determines the number of completions in a well and their spacing (King, 2010). The PnP system takes more time to complete than OHMS but allows for more freedom in locating fractures. The OHMS completions are more constrained with respect to the upper limit of fracture stages per well, although this limit has been improving with time (Themig, 2011). Additionally, OHMS reduces the time that fracture fluid is in contact with the rock; therefore, it reduces the risk of formation damage.

Fracture completions are used to increase well production by increasing the volume of rock that can connect with the wellbore or the 'stimulated reservoir volume'. Because hydraulic fracturing is expensive but necessary for increased production, the number of completions per well is generally optimized in long horizontal wells with many fracture stages (Cipolla et al., 2009; McDaniel and Rispler, 2009; Schweitzer and Bilgesu, 2009). If there are too few fracture stages per well, production may not be maximized. Conversely, stages that are too tightly spaced can increase the risk of 'screen out' or longitudinal fractures, which also impair production (Roussel and Sharma, 2010). Taylor et al. (2010) hypothesizes that 75 m is an ideal spacing for most shale gas reservoirs.

In northeast British Columbia, three types of completions (or treatments) are generally used: slickwater, energized and energized slickwater. The treatment style used is a function of economics and geology (King, 2010). Slickwater treatments use high volumes of water with low concentrations of sand and trace amounts of friction-reducing chemicals. This treatment type tends to propagate large fractures and as such is generally the most economical treatment choice (Kazakov and Miskimins, 2011). Slickwater fractures propagate best in brittle heterogeneous rock with higher silica content and lower clay content, as is the case in the Barnett shale (Mayerhofer et al., 2008; Buller et al., 2010; East et al., 2010; Wang and Miskimins, 2010). Long complex fracture networks created by this technique enhance the well's stimulated reservoir volume (Taylor et al., 2010); however, slickwater fractures have low sand concentration with rapid proppant settling. As a result, fracture flow capacity can be limited (King, 2010). An additional challenge is that these completions often have return water rates of less than 30% (Burke et al., 2011). Slickwater fracture treatments are not practical for all geological environments.

Energized treatments are the method of choice for softer, more ductile rocks such as siltstone or shale with clay or carbonate rocks and underpressured horizons. Energized treatments use comparatively small amounts of water, relying instead on the use of foams and polymers to support the suspension of large concentrations of sand. Softer rock formations have the capacity to absorb the stress of a stimulation treatment without necessarily generating a fracture network (Buller, 2010). The higher proppant concentrations that characterize energized treatments help to keep fractures open because softer rocks tend to heal quickly (East et al., 2010).

Energizing components also provide quick and efficient fluid return to surface (flowback; Bene et al., 2007; Warpinski et al., 2008). The percentage of return water from energized treatments can be up to 70% (Arthur et al., 2008). Because low permeability can cause a capillary effect that draws water into the formation and low reservoir pressures do not create enough flow for the gas to displace the liquid from the formation (Wylie et al., 2007), compressed gases such as carbon dioxide (CO_2) or nitrogen gas (N_2) are used to help 'energize' the return of water to the surface. Formation damage can occur if water-sensitive clays are present that might swell and block gas migration pathways (Bene et al., 2007; Taylor et al., 2009). Depth is also a factor in the effectiveness of energized fluids. Energized fluids lose their ability to transport proppant at greater depths because the fluids are less able to generate bubbles; therefore, slickwater treatments may be more appropriate in these environments.

If an environment is equally conducive to both slickwater and energized fractures, slickwater fractures generate a higher stimulated reservoir volume and better production at a lower cost than energized fractures (Romanson et al., 2010). Energized treatments perform better in softer rocks, although the fracture halflength is less and the cost of treatment is greater (East et al., 2010; Burke et al., 2011). Table 1 shows how treatment types vary with brittleness and geology.

Energized slickwater treatments are a hybrid of both types and are not clearly defined in the literature. In general, the large amounts of water associated with slickwater completions are used in combination with the compressed gases used to create foams in energized treatments. The rationale for using energized slickwater treatments is to create a large stimulated reservoir volume while mitigating problems associated with water in the formation, such as formation damage and reduced flowback (Zelenev et al., 2010; Burke et al., 2011). Compressed gases, such as N_2, are often used.

In terms of the fluids used for completions, either energized or nonenergized fluids, polymer gels can be used in varying degrees and configurations to increase the viscosity of the fluid to support proppant in solution (Kargbo et al., 2010; LaFollette, 2010). Initially, treatments were freshwater based, although saline water can now be used in both energized and slickwater treatments by employing specialized friction-reducing agents. The reuse of fracture fluid can improve well economics (Paktinat et al., 2011).

Current Assumptions about hydraulic Fracture–Related Water Use in British Columbia

The National Energy Board (2009) indicates that hydraulically fracturing wells can be water-intensive procedures; however, data are limited. Water is not necessarily required for all hydraulic fracturing in gas-bearing shale; yet, high volumes are required for developing the HRB shale. It is important to understand the differences in order to understand regional water demand.

To date, most of the assumptions made on industry-required volumes and the rate of usage in British Columbia has been based on general knowledge of the province's two major plays: the Montney Basin and the HRB. This range represents a significant difference in the amount of water required by industry for multistage hydraulic fracturing. In the Montney Trend, water demand can be from 200 m^3 to 4600 m^3 water per fracture stage with wells needing 800 to 13 000 m^3 water per well (Dunk, 2010; Burke et al., 2011). In the Horn River Basin, water demand ranges from 2500 to 5000 m^3 per fracture stage with values ranging from 10 000 to 70 000m^3 per well (Horn River Producers Group, 2011).

A more thorough assessment of water demand in northeast British Columbia is required. Meaningful analysis will establish whether specific conditions exist for the rates of water usage, and whether a combined analysis of water use in the Montney Basin and the HRB is a meaningful proxy for industry-related water-use requirements in other areas.

TABLE 1. FRACTURE TREATMENT VARIATION WITH BRITTLENESS (ADAPTED FROM BULLER, 2010).

Brittleness	Fluid Viscosity	Energized	Fluid Volume	Proppant Volume	Proppant	Example
70%	Slickwater	No	High	Low	Low	Muskwa, Barnett
60%	Slickwater					
50%	Hybrid					Marcellus
40%	Linear gel					
30%	Crosslnked gel					
20%	Crosslinked gel					Haynesville
10%	Crosslinked gel	Yes	Low	High	high	

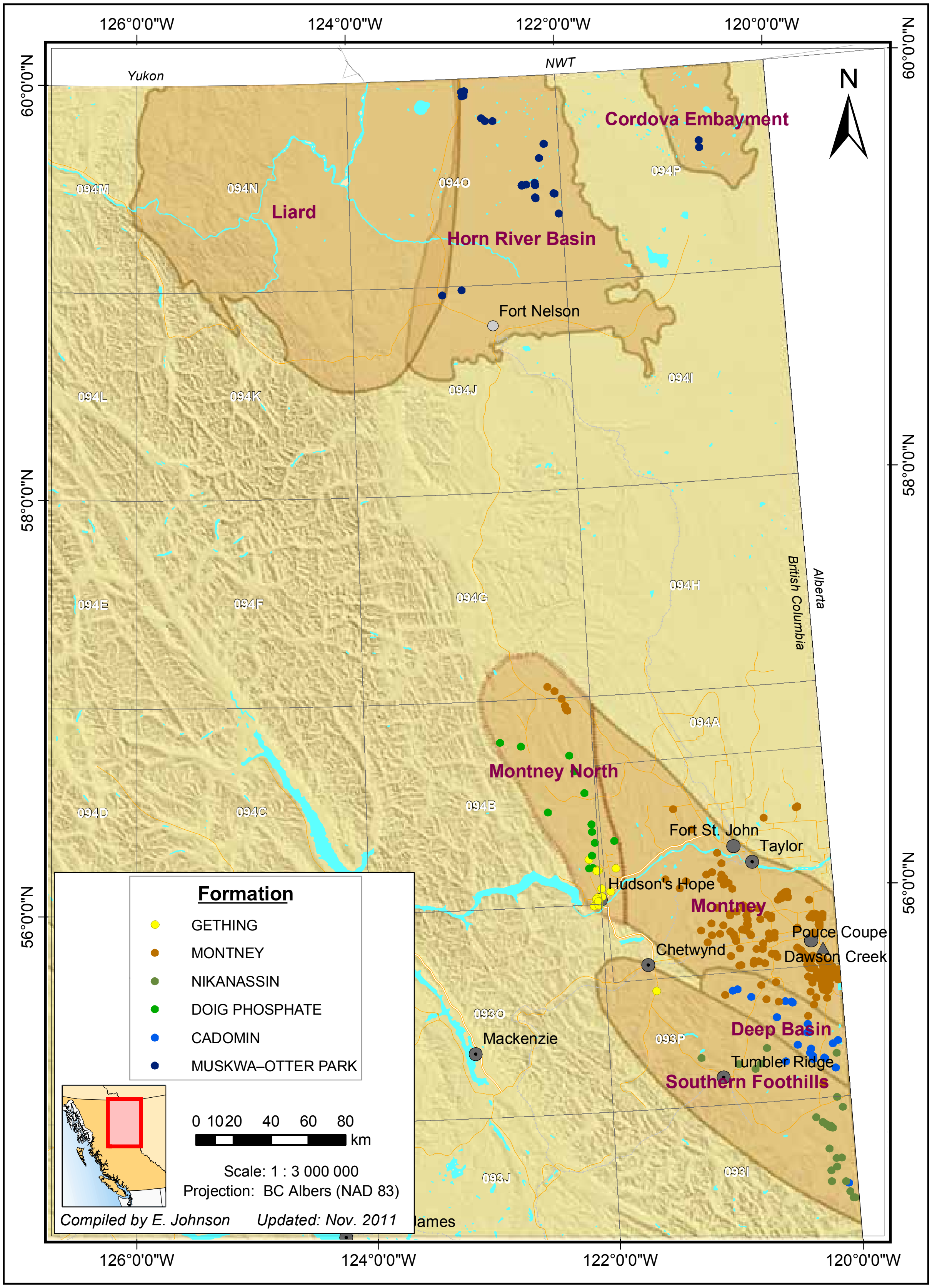

Figure 1. Major basins with multistage fracturing in northeast British Columbia. Wells are indicated as solid dots and formations are grouped by colour.

TABLE 2. GEOLOGICAL ASPECTS OF HORIZONS WITH MULTISTAGE FRACTURING.

Formation	Target	Depth Average (m)	Pressure Average (kPa)	Gradient Average (kPa/m)	Temperature Average (°C)
MONTNEY	Siltstone and shale	2300	31500	2.3	86
MUSKWA–OTTER PARK	Shale	2600	39300	2.1	115
EVIE	Shale	2800	41200	2.2	142
DOIG PHOSPHATE	Shale	2200	31200	2.1	71
CADOMIN	Sandstone and conglomerate	2500	16700	0.9	80
NIKANASSIN	Sandstone with shale & siltstone	2900	26100	1.6	103
GETHING	Coal	700	8200	0.4	39

Geology of the major basins

Geological aspects such as the lithology, geochemistry and petrophysics of a formation are partially determined by the depositional environment. The following section provides a brief geological summary of the target formations in the basins of northeast British Columbia. Figure 1 shows the geographic distribution of the basins. Table 2 provides a brief summary of the lithology, depth, pressure and gradients for the formations.

MONTNEY TREND AND MONTNEY NORTH TREND (MONTNEY, DOIG PHOSPHATE AND GETHING SHALES)

The sandstone, siltstone and shale of the Triassic Doig and Montney formations in northeast British Columbia were deposited on a westward-prograding shelf on the paleocontinental margin (Edwards et al., 1994). Sediments grade westerly from near-shore fine-grained sandstone and siltstone deposits to deep-water shale (Walsh et al., 2006). The lithology in the Montney Trend changes to the northeast and sediments have increased silica and shale content leading to different completion practices. In this report, the Montney North Trend is defined as a separate region.

Shale gas potential exists in two zones: 1) the Lower Montney, in sandy, silty shale of the offshore parts of the basin and 2) the Upper Montney, below the shoreface, where silt has buried tight sand (National Energy Board, 2009). The Montney is locally more than 300 m thick and is developed in portions using stacked horizontal wells. The Montney play is a world-class natural gas play and it is estimated to contain an original-gas-in-place of 35–250 trillion cubic feet (Tcf) of natural gas (Adams, 2010). In some areas, the Montney is a dry-gas reservoir, transitioning to an oil reservoir in other areas with retrograde condensate production in transition areas (Taylor et al., 2009).

The contact between the Montney Formation and the overlying Doig Formation is marked by a distinctive shale unit with abundant phosphatic grains (the Doig Phosphate). The Doig shale above the phosphate grades upwards into a clean shoreface sandstone that in many areas is indistinguishable from the overlying Halfway Formation (Walsh et al., 2006). In the Montney North region, the Doig Phosphate is predominantly shale.

The Gething Formation is a coal-bearing formation that consists of two coal measures separated by a sandstone-siltstone layer (Legun, 1991). The formation contains cumulative coal thicknesses that range up to 17 m. As the coal is mostly high-volatile A bituminous, the Gething is being developed for coalbed methane (CBM; Ryan et al., 2005). North and south of Hudson's Hope, the formation dips moderately to the east and it is generally too deep for development.

HORN RIVER BASIN AND CORDOVA EMBAYMENT (EVIE, OTTER PARK AND MUSKWA FORMATIONS)

The Horn River Basin (HRB) and the Cordova Embayment formed during the Middle Devonian when the Presqu'ile barrier reef extended northward along the eastern edge of the Horn River Basin (Fig. 2). Clay, siliceous mud and organic debris deposited on either side of the reef formed the Evie, Otter Park and Muskwa shale members of the Horn River Group (British Columbia Ministry of Energy and Mines and National Energy Board, 2011); hence, the shales targeted for development in the HRB are the same as those in the Cordova Embayment.

The Evie member is the lowermost shale. It consists of organic-rich, variably calcareous and siliceous shale. The uppermost part of the unit includes more silt. In the Horn River Basin, the Evie thins westward from more than 75 m to less than 40 m thick in the vicinity of the Bovie Lake structure on the western margin (British Columbia Ministry of Energy and Mines and National Energy Board, 2011).

The Otter Park member consists of calcareous shale. This shale reaches a maximum thickness of more than 270

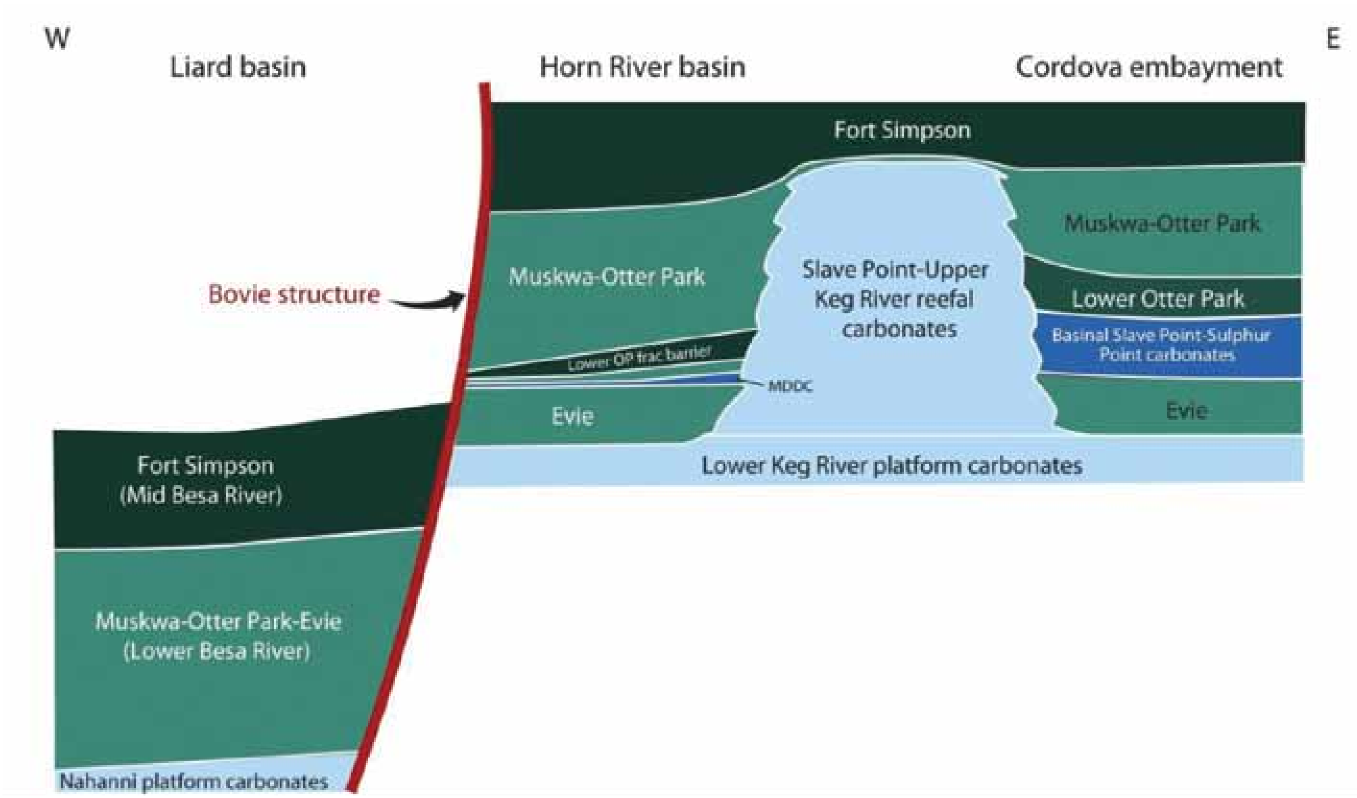

Figure 2. Illustrated cross section depicting shale of the Horn River Basin and the Cordova Embayment separated by the Presqu'ile barrier reef (Ministry of Energy and Mines and National Energy Board, 2011).

m in the southeast corner of the Horn River Basin. The shale thins to the north and west, where it includes siliceous black interbeds (British Columbia Ministry of Energy and Mines and National Energy Board, 2011).

The Muskwa member consists of organic-rich, siliceous shale. In the Horn River Basin, the Muskwa is 30 m thick adjacent to the Presqu'ile barrier reef and thickens westward to more than 60 m. The exception to this pattern is in the southeast corner of the Horn River Basin, where the Muskwa thins considerably and the Otter Park thickness reaches its maximum. The Muskwa is not restricted to the Horn River Basin but thins and extends over the top of the barrier reef and is present through the rest of northeast British Columbia strata (British Columbia Ministry of Energy and Mines and National Energy Board, 2011). The Muskwa and Otter Park shales are coupled together for this research.

DEEP BASIN (CADOMIN FORMATION)

The Cadomin Formation is the oldest unit in the Deep Basin and unconformably overlies the Nikanassin Group. The Cadomin is derived from sediments from the west that were transported northwards. It contains widespread sandstone and conglomerate that range from 5 to 25 m thick. A maximum thickness of approximately 170 m is reached in the area southwest of Monias (Tuffs et al., 2005).

Industry has recognized the Cadomin as a potential gas target for more than two decades but early forecast reserves have not yet been realized. Deep Basin Cadomin fields are underpressured. Prior to 2001, there was no commercial gas production from the Cadomin in northeast British Columbia. Industry had drilled 250 vertical wells that penetrated the Cadomin Formation (Cutbank Ridge area) but only 20 had flowed gas. In 2001, hydraulically fractured vertical and horizontal wells in lower-permeability reservoirs in the thicker Cadomin sections of British Columbia yielded economic gas returns.

LIARD BASIN (BESA RIVER FORMATION)

The Liard Basin formed through continuous subsidence and deposition from the Cambrian to the Late Silurian. Late Devonian uplift caused a thickened succession in the northern and eastern parts of the basin (CBM Solutions, 2005).

The Besa River shale has been identified as a source rock zone and a potential fractured reservoir. It is just beginning to be economically developed. The Besa River represents the deep-basin equivalent formations to the package, including the succession from the Horn River Formation to the Debolt Formation (Fig. 3). The Besa River Formation contains carbonaceous siltstone to shale units and is more than 2000 m thick (CBM Solutions, 2005). There is

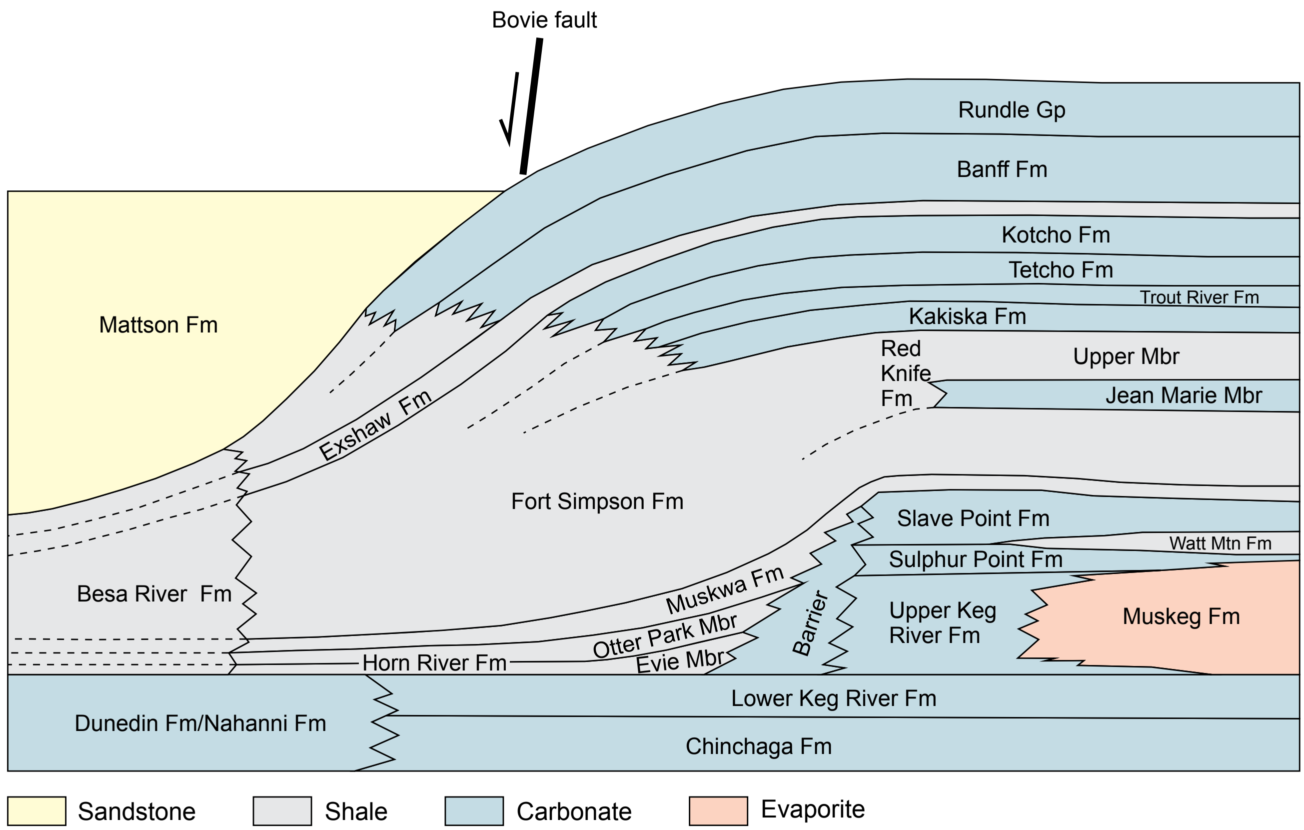

Figure 3. Schematic diagram shows the transition (in grey) between the Besa River Formation in the Liard Basin (left) to the package in the Horn River Basin (right), which ranges from the Evie, Muskwa–Otter Park members through the Debolt Formation (Ferri et al., 2011).

a central unit in the Besa River Formation of siliceous siltstone, which is correlated with the Fort Simpson Formation (Ferri et al., 2011).

SOUTHERN FOOTHILLS (NIKANASSIN GROUP)

The Nikanassin Group represents a thick clastic wedge of sediments that thins to the east. It is composed of various very fine to medium-grained sandstone beds with interbedded shale and siltstone (carbonaceous in part), and various coal beds. Sandstone intervals have intergranular and fracture porosity that is generally less than 6% with permeabilities less than 0.1 mD, so there is tight gas potential. In northeast British Columbia, the Nikanassin consists of the Minnes Group, including the Monteith, Beattie Peaks, Monach and Bickford formations, from oldest to youngest (Stott, 1998; Miles et al., 2009). Gas development includes directional wells parallel to bedding planes within fold limbs.

METHODS

A database of well information was compiled with data from the OGC Integrated Resource Information System (IRIS) database and augmented with data from IHS AccuMap® and geoLOGIC Systems geoSCOUT program. The new database was constructed to focus on metrics related to multistage hydraulic fracturing; therefore, it does not include data from all wells, only those with fracture completion information (7117 wells out of the 30 997 wells in British Columbia as of September 2011 where a ‘well’ consists of a unique well identifier and completion event, UWI-CE). Most of the data is complete through to the end of 2010. Much of the fracture completion information is manually verified by OGC staff, so the records in the IRIS database lag behind the current date by approximately six months.

Only wells with more than three stages per well event were included in the multistage hydraulic fracturing research. Patterns emerged from the initial database of more than 7000 wells when the threshold for ‘multistage’ was set. There were 509 wells with multiple completions. Thirteen of these wells were eliminated because they were outside the time and space guidelines for this project (completed after 2003 and in northeast British Columbia). The remaining 496 wells were used for analysis. Some of the well data are confidential and are included with group data for trend analysis, but excluded in regions where drilling is too sparse to ensure the confidentiality of the operators, specifically in the Cordova Embayment and the Liard Basin.

Not all basins were analyzed at all stages of this study. Many of the analyses focused specifically on horizontal multistage wells (399 wells) in the Montney Trend, the Montney North Trend, the Deep Basin and the Horn River Basin. Some exclusions are noted below:

- Gething wells were excluded from most analyses. Hydraulic fracturing associated with the Gething Formation is substantively different than for other shale and tight gas targets because Gething wells are focused on coalbed methane extraction. Well depths are comparatively shallow, wells are vertical and water usage in hydraulic fracturing is minimal.
- Nikanassin Group wells were excluded from some analyses. Nikanassin wells target tight gas with typically four to six fracture stages along directional wells with nominal water usage. Because these wells are directional, not horizontal, they were not directly comparable for all comparisons with horizontal wells.
- The Cadomin Formation was included in the analyses, but it should be noted that it is not classified as unconventional. Wells target conglomerate and sandstone in a low-pressure environment; however, the approach taken to development uses high-volume horizontal multistage (HVHMS) completions, so this formation was included.
- Wells from the Cordova Embayment are too few to be representative.

Compiled data fields for analysis include both well data (e.g., location, operator, dates, field, orientation, confidential status and formation) and fracture-specific information (e.g., fracture depth, stimulation volume, dates, comments and stimulation pressure). Production data were included, where available. These data included date, volume of gas per producing day, water per producing day and cumulative totals.

Much of the fracture data was in the 'comments' field of the IRIS database. This field was analyzed to determine proppant mass per fracture, fracture treatment type (energized with CO_2 or N_2, slickwater or nitrified slickwater) and fracture type (refracture, failed fracture, data fracture injection fracture or mini fracture). The style of treatment was not determined for 12% of wells in the database. Well data were categorized by location into basins and enhanced with analyzed fracture data for the lateral length, average fracture spacing, average stimulation volume per fracture, stimulation volume per well, average proppant mass per fracture, proppant mass per well, average stimulation pressure, dominant treatment type, water to sand ratio and pressure-depth gradient.

There was some ambiguity in the database where mini fractures were used test the character of the rock in advance of a full hydraulic fracture. The water usage for injection tests, data fractures, mini fractures is small and these fractures were excluded from the analyses. There was also some duplication where failed fracture attempts and refracturing efforts were recorded. Although it would be desirable to separate out these events from the overall fracture database, it was not feasible given the nature of the data entries. Efforts were made, however, to exclude these events when calculating fracture spacing and averages of water and sand for the well so that the data would not be unduly biased.

The average spacing between fracture stages was calculated by two methods. The first method involved taking the distance from the top of the shallowest stage to the bottom of the deepest stage and dividing by the number of stages. The second method involved calculating the offset distance between each stage and calculating the average for the well. Differences between the two methods were found to be negligible. As such, the offset method was used to generate spacing distance for the analyses.

Well and fracture data were analyzed for relationships and trends by crossreferencing. Microsoft® Excel® software was used for common statistical analysis including histograms and linear regression. Variables assessed included date, stimulation volume (by fracture or by well), mass of proppant, ratio of water to proppant, gas production from the first four months and gas production after 24 months. Common groupings included formation, basin, treatment type and stimulation volume (low, moderate, high).

The spatial distribution and grouping by basin for the formation fractured, well orientation, treatment type and the stimulation volume of water was evaluated using ESRI® ArcGIS®.

Production rate, cumulative production and returned water curves were created as averages for formation, basin and treatment type. Approximately half of the wells in the database have two years or more of public gas production information (243 wells). The majority of wells are in the Montney Formation (190 wells). There were not enough producing wells in the Doig Phosphate (three wells) or the Evie member (four wells) to be representative. Production data were isolated for production after 24 months and crossreferenced with stimulation volume and lateral length. A metric for water usage was developed by normalizing the water used for fracturing a well against cumulative gas production after two years for that well. Note that this metric is not directly comparable with published metrics for the volume of water used relative to the estimated ultimate recovery of gas.

Comparisons were made between production rates (gas units per producing day) and i) well stimulation volumes, ii) sand placed in formation and iii) the number of fracturing stages. Correlation analysis was performed between water consumption indicators and initial gas production (an average of the production for the first four months), and production after two years. This analysis was performed for gas production both as a volume per producing day and as a cumulative volume. Basins were compared by the amount of water required to develop a unit of gas after two years of production.

RESULTS

Research results are grouped into two main sets of findings pertaining to 1) the location, history of development and trends in multistage horizontal wells in northeast British Columbia and 2) the interrelationship between the number and style of completion with water usage and production.

Development trends

Almost all the multistage hydraulic wells are located in a small number of formations and are restricted to a few basins. More than 96% of multistage wells are located in seven formations and five basins (Fig. 1). These formations include the Montney Formation along the Montney Trend; the Doig Phosphate horizon in the Montney North region; the Muskwa, Otter Park and Evie members in the Horn River Basin; the Cadomin Formation in the Deep Basin; and the Nikanassin Group in the Montney Trend and Southern Foothills (Table 3).

Multistage wells across northeast British Columbia are predominantly horizontally oriented in keeping with the stratigraphic orientation for the Western Canadian Sedimentary Basin in northeast British Columbia. The average depth for multistage horizontal wells is more than 2 km (Table 2). Vertical wells are common near Hudson's Hope, where they are used to develop the Gething coalbed methane at a depth of approximately 1 km. Directional wells were closer to the deformed belt in the Southern Foothills, where Nikanassin sandstone and conglomerate sediment dip. Table 4 shows the relative number of wells and their orientation.

Overall, the Montney Trend has been the most active of the five major basins with the most wells drilled. Of the total number of multistage horizontal wells (496), 310 are located in the Montney Formation within the Montney Trend. Development with horizontal multistage hydraulic wells began in 2005 and has been the most quickly developed of the basins. Multistage drilling began in the HRB in 2007, but at a much slower pace. By 2010, there was more than five times the number of multistage horizontal wells in the Montney Trend than in the HRB (Fig. 4). Drilling in the Deep Basin has been ongoing for more than a decade with ever-increasing technological complexity. Multistage horizontal drilling began in 2007, but the number of new wells has tapered off since 2008. Multistage drilling began more recently in the Montney North (in 2008) and has since increased steadily. Development of the Nikanassin Group began in the Montney Trend in 2005 and continued in the Southern Foothills in 2007, although the number of wells drilled (26) is insignificant compared to the number drilled in the Montney Formation.

TABLE 3. MULTISTAGE WELLS BY BASIN AND FORMATION IN NORTHEAST BRITISH COLUMBIA.

Formation	Montney Trend	Horn River Basin	Montney North Trend	Deep Basin	Southern Foothills Trend	Grand Total
MONTNEY	310		7			317
DOIG PHOSPHATE			13			13
GETHING	2		16		1	19
MUSKWA-OTTER PARK		46				46
EVIE		20				20
CADOMIN				31		31
NIKANASSIN	15				11	26
Grand Total	327	66	36	31	12	472

TABLE 4. WELLBORE ORIENTATION FOR FORMATIONS IN NORTHEAST BRITISH COLUMBIA.

Formation	Vertical	Horizontal	Directional
MONTNEY	5%	87%	8%
DOIG PHOSPHATE	15%	54%	31%
GETHING	95%		5%
MUSKWA–OTTER PARK	8%	92%	
EVIE		100%	
CADOMIN		90%	10%
NIKANASSIN			100%

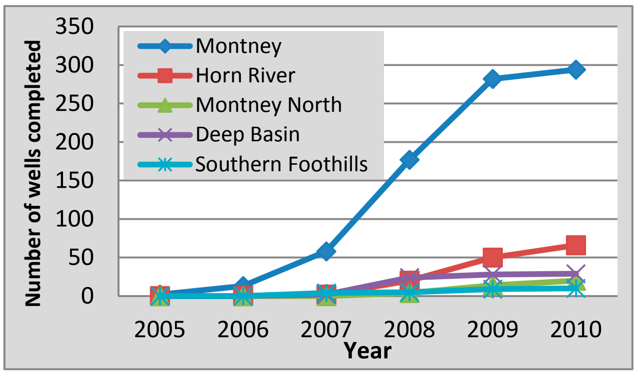

Figure 4. Development activity showing the well count for multistage wells in northeast British Columbia by basin.

Completions, water use and production

A strong uniformity in the stimulation treatment is employed for any given basin (Fig. 5). This uniformity exists irrespective of operator. Multistage hydraulic wells in the HRB were almost exclusively slickwater completions. Slickwater treatments were also the primary system employed in the development of the Deep Basin Cadomin sandstone and conglomerate. Wells in the Montney were predominantly energized. The only exceptions to uniformity in treatment type within regions were the Montney North and Southern Foothills. A diversity of treatment methods were used here (Table 5). The majority of energized treatments were CO_2 based, although energized slickwater treatments are predominantly N_2 based.

The number of fracture stages per well has increased across northeast British Columbia, except in the Southern Foothills, where four to six fractures per well are consistently used. In regions where slickwater fracturing has become the preferred treatment method (e.g., the HRB, the Deep Basin), the number of fracture stages per well has increased dramatically (Fig. 6). From 2009 to 2010, operators almost doubled the number of fracture stages per well from 10 to 19 in the Horn River Basin. Fracture stages increased dramatically for the same period in the Deep Basin, from 9 to 15. Increases were modest in the Montney and Montney North trends. Increased production was associated with increased numbers of fracture stages in the HRB and the Deep Basin (Fig. 7). Conversely, production did not improve for energized wells in the Montney.

There has also been a general trend towards reduced spacing between fractures over time in northeast British Columbia. For instance, the spacing between completions decreased steadily in both the HRB shale and the Montney Formation (Fig. 8). At present, completions are commonly less than 150 m apart, having tightened up from more than 300 m apart in 2005.

The lateral length of wellbores for multistage wells in northeast British Columbia has also increased annually. Lateral length was 1800 m for both the HRB and the Montney Trend (Fig. 9). The increase in lateral lengths for wells in the HRB was far faster than for the Montney Trend, which showed a stepwise increase with increments of 300 m over 5 years, whereas the horizontal lengths in HRB increase annually by 200 m or more. Further analysis revealed a relationship between the fractured horizontal length and well productivity in the HRB (Fig. 10). A positive exponential relationship was found between the lateral length of a well and gas production for the Muskwa–Otter Park shales. Increasing the total horizontal fracture distance from 0.5 to 1.5 km translated to an increase in gas output from 600 to 3600 e^3m^3 per well after two years of production. No similar relationship was found between lateral length and productivity for energized wells in the Montney.

In terms of water usage, slickwater treatments were the most water-intensive technique, using 13 times more water per fracture than an energized fracture (Table 5). On average, slickwater treatments used 2100 m^3 per stage. By comparison, the average energized treatments (CO_2) used approximately 155 m^3 per fracture stage. Hybrid energized slickwater treatments require approximately 800 m^3 per fracture stage. Significant variability exists in the amount of water used for any given slickwater treatment. In both the HRB and the Deep Basin, slickwater water volumes vary over an order of magnitude, from 400 m^3 to almost 5000 m^3; however, the nature of the distribution of volumes in the HRB is different from the distribution in the Deep Basin. The mean fracture volume for the Deep Basin is half that of the HRB.

Differences in consumed water volumes were also found between the various basins. Water consumption in the HRB was climbing at a far faster rate than in other basins (Fig. 11). The cumulative volume of water used in the HRB was almost four times greater than that used in the Montney Trend despite the substantial difference in well numbers. The difference in consumption between the HRB and Montney changed from 1.5:1 in 2008, to 2.1:1 in 2009 to 3.5:1 in 2010. Note that development activity and water consumption in the Deep Basin did not keep pace with

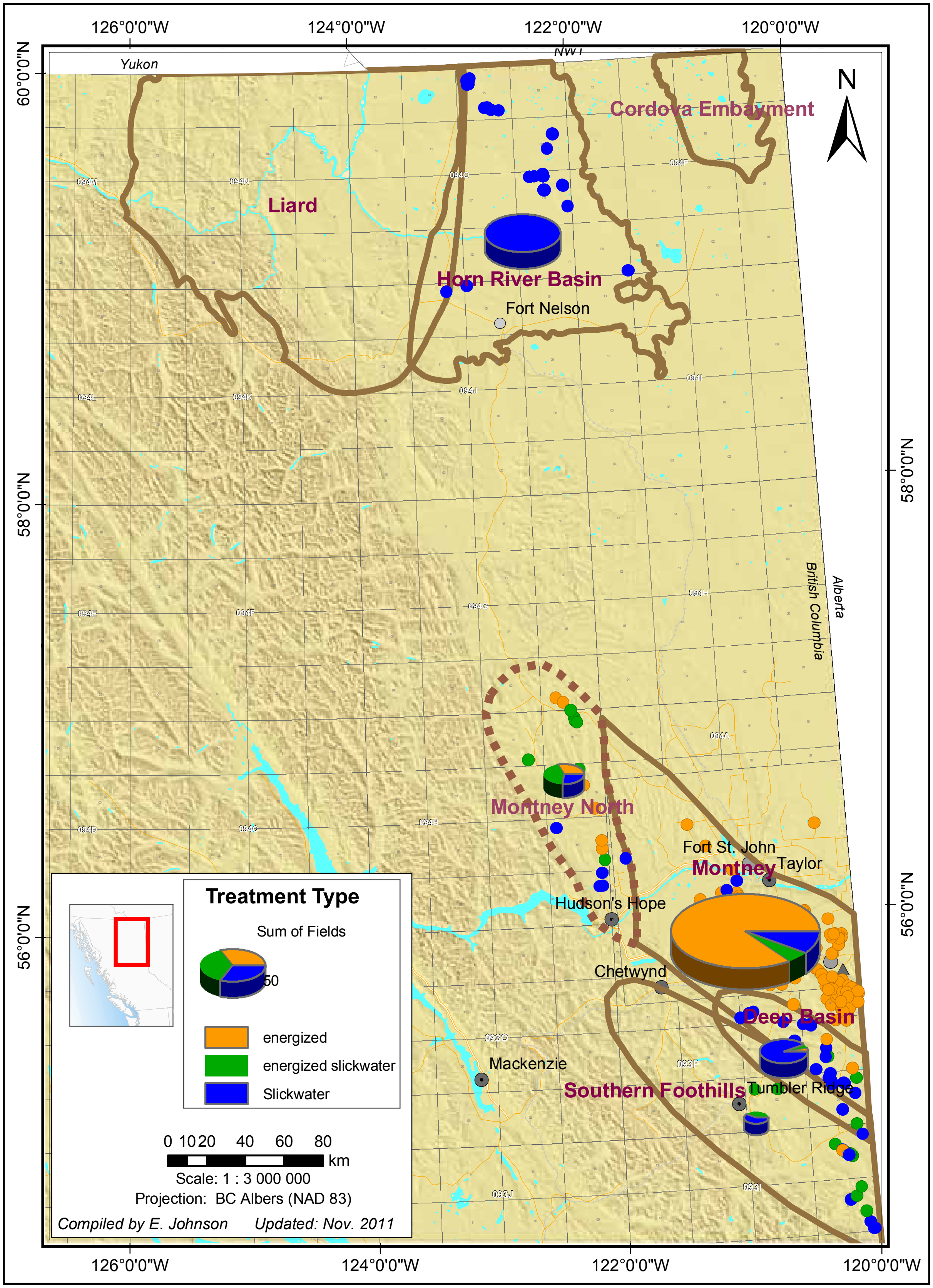

Figure 5. Types of fracture treatments and their distribution across northeast British Columbia. Wells are colour-coded by treatment type and pie charts represent the relative proportion of treatment types for wells a given basin.

TABLE 5. ATTRIBUTES OF FRACTURE TREATMENT METHODS USED IN NORTHEAST BRITISH COLUMBIA.

Frac Treatment	Sub-type	Water per Stage (m^3)	Sand per Stage (T)	Stimulation Pressure (kPa)	Water/ sand (m^3/T)	Count of Fractures
Energized	CO_2	155	95	56134	2	5585
	CO_2/N_2	134	113	48347	1	601
	N_2	227	101	53092	2	1691
		168	**98**	**54880**	**2**	**7877**
Energized slickwater	CO_2 slickwater	443	64	54436	9	44
	Nitrified Slickwater	822	136	52374	10	550
		791	**130**	**52541**	**10**	**594**
Slickwater		2101	178	59827	14	8126
		2101	**178**	**59827**	**14**	**8126**

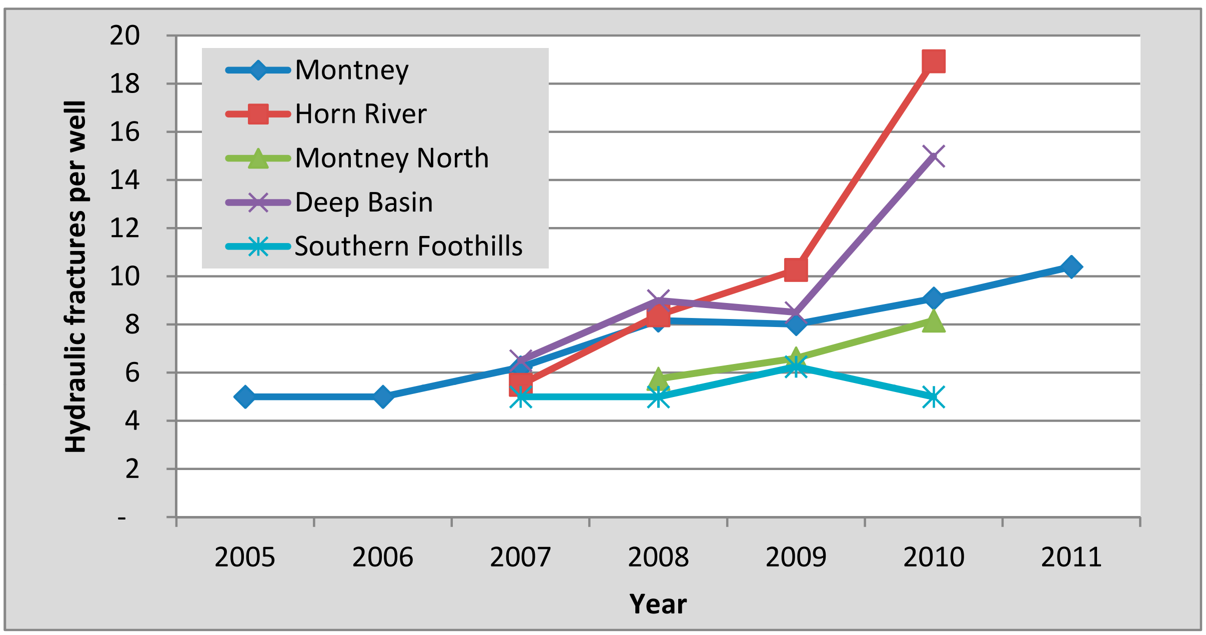

Figure 6. Average number of fracture stages for wells by basin between 2005 and 2010.

HRB (Fig. 4, 11).

The ratios of the volume of water required to develop a unit of gas varied significantly by basin (Fig. 12). In the Montney Trend, very little water was required to produce gas, averaging 0.06 m^3 per unit gas (where a unit of gas is 1000 m^3 measured after 24 months of production). The amount of water necessary to produce gas is higher for the Montney North, the Deep Basin and the HRB (0.2, 0.3 and 0.5 m^3 water per unit gas, respectively).

A strong relationship was found to exist between the initial daily production rate and fracture features (stimulation volume and proppant placed in formation) for slickwater fractures in the Muskwa–Otter Park shales (Table 6). The relationship between stimulation volume and production strengthened with time (Table 7). This indicates that stimulation volume injected in a slickwater fracture reflects the stimulated reservoir volume with gas production coming from deep fractures beyond the immediate vicinity of the wellbore. The relationship was not as strong between proppant and production because sand

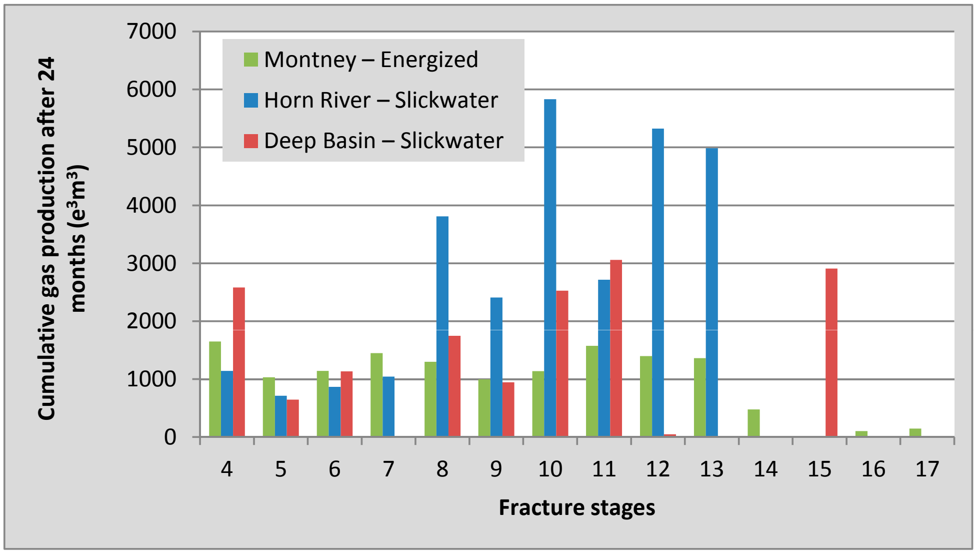

Figure 7. Produced gas as a function of the number of fracture stages per well.

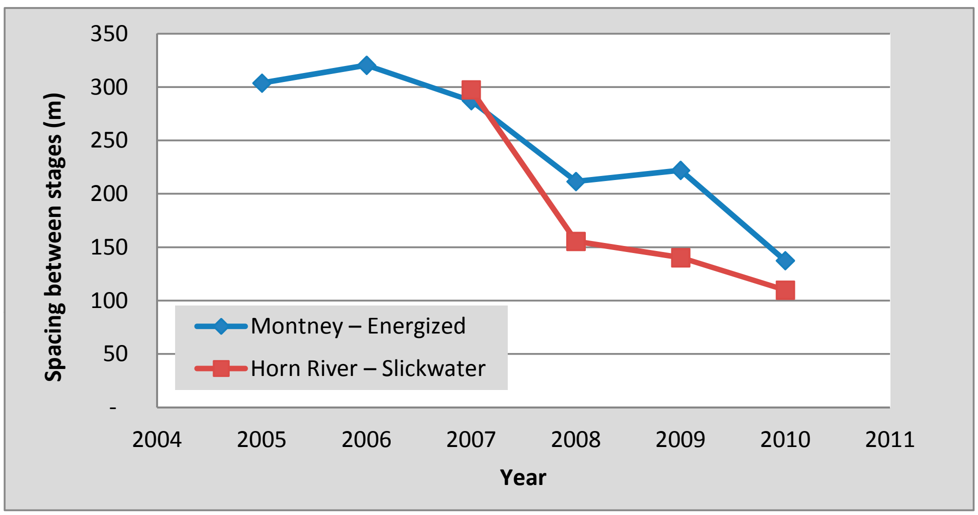

Figure 8. Changes in the average spacing between fracture stages from 2005 to 2010.

falls out of suspension during injection and therefore does not represent the stimulated reservoir volume as precisely as water volume. There was only a weak relationship between daily production and the number of fracture stages per well. There was no relationship between production rate and fracture features or number of fractures for the Montney. Weak relationships exist in the Nikanassin Group for fracture features and production rate but not number of fractures and production rate.

The strong linear relationship between production rate and stimulation volume is displayed graphically in Figure 13. Although there are not many wells with a long production history in the HRB, the relationship is sufficiently statistically significant to be predictive. For the Muskwa–Otter Park members, the rate of gas production after two years will be roughly 0.0018 the original stimulation volume used.

The production curves for the Muskwa–Otter Park shales show that increased stimulation yields increased production at all points in the production history (Fig. 14). This has implications for the estimated ultimate recovery from a well. The curves generally maintain their separation for more than 36 months of production, although small improvements in production from slightly higher stimulation volumes wane over time. Large production improvements from large volumes persist. The higher the stimulation volume, the greater the production rate and estimated ultimate recovery. Raising the stimulation volume by 23 000 m^3 (from 11 600 m^3 to 34 600 m^3) yielded 45 500 e^3m^3 more gas over 24 months.

In general, the return volumes reported were low compared to the literature (Fig. 15). The volume of return water from slickwater treatments was very small. In the HRB, slickwater return in the 20 months following well completion was only 17%. The use of nitrogen (N_2) with slickwater

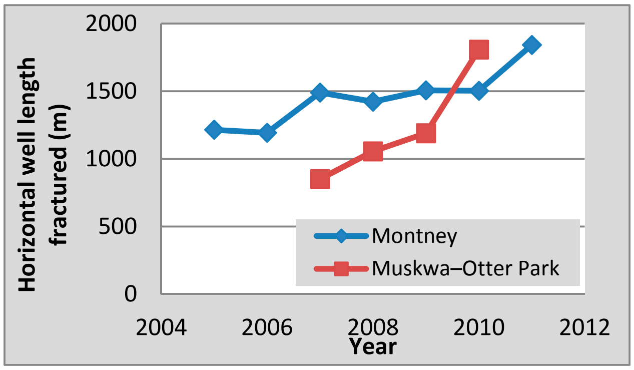

Figure 9. Average horizontal wellbore lengths for two formations between 2005 and 2010.

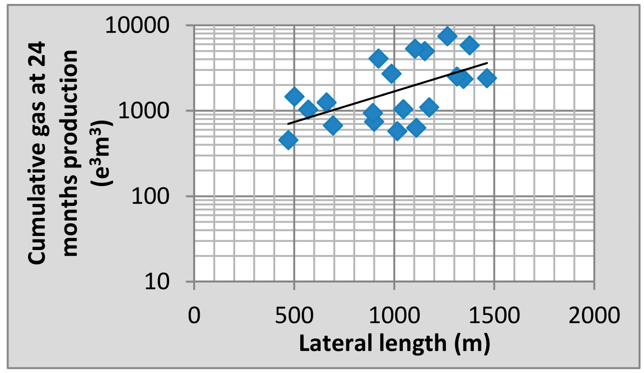

Figure 10. Cumulative gas production after 24 months for wells in the Muskwa–Otter Park shales in the Horn River Basin.

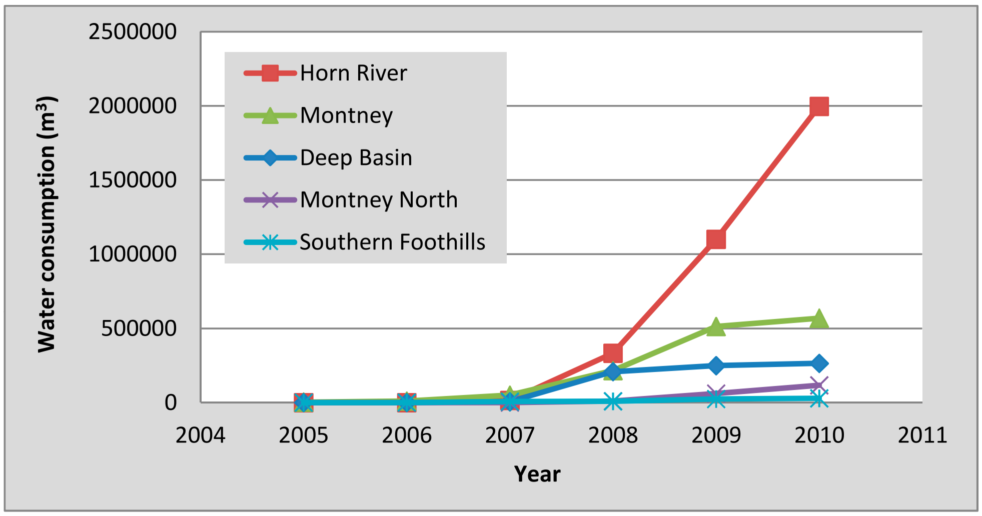

Figure 11. Cumulative water consumption by basin between 2005 and 2010.

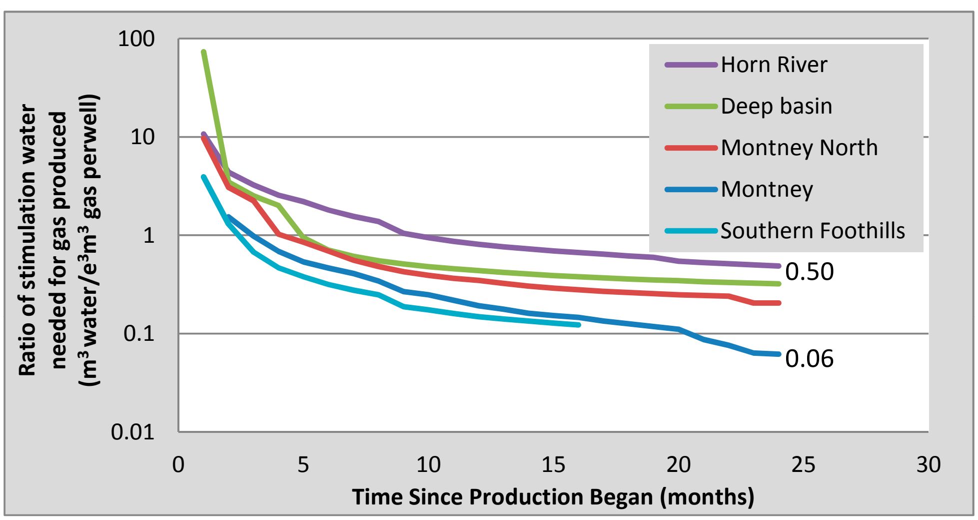

Figure 12. Average ratio by basin of the water initially required for hydraulic fracturing to develop every 1000 m^3 gas.

TABLE 6. CORRELATION COEFFICIENT (R2) BETWEEN GAS PRODUCTION RATES AND HYDRAULIC FRACTURING OVER THE FIRST FOUR MONTHS OF PRODUCTION. SIGNIFICANT CORRELATIONS, THOSE WITH AN R^2 VALUE MORE THAN 0.75 ARE HIGHLIGHTED IN BOLD TEXT.

Gas production for the first 4 months (e^3m^3/day)	Formation	Stimulation water per well (m^3)	Sand per well (T)	Number of frac stages
Energized	Montney	0.06	0.01	0
Energized Slickwater	Nikanassin	0.37	0.53	0.11
Slickwater	Muskwa–Otter Park	**0.83**	**0.82**	0.47
	Cadomin	0.51	0.68	0.34

TABLE 7. CORRELATION COEFFICIENT (R2) BETWEEN GAS PRODUCTION RATES AND HYDRAULIC FRACTURING AFTER TWO YEARS OF PRODUCTION. SIGNIFICANT CORRELATIONS, THOSE WITH AN R^2 VALUE OVER 0.75, ARE HIGHLIGHTED IN BOLD TEXT.

Gas production at 2 years (e^3m^3/day)	Formation	Stimulation water per well (m^3)	Sand per well (T)	Number of frac stages
Energized	Montney	0.01	0.06	0.02
Energized Slickwater	Nikanassin	**0.79**	0.4	0
Slickwater	Muskwa–Otter Park	**0.9**	**0.71**	0.31
	Cadomin	0.2	NA	0.06

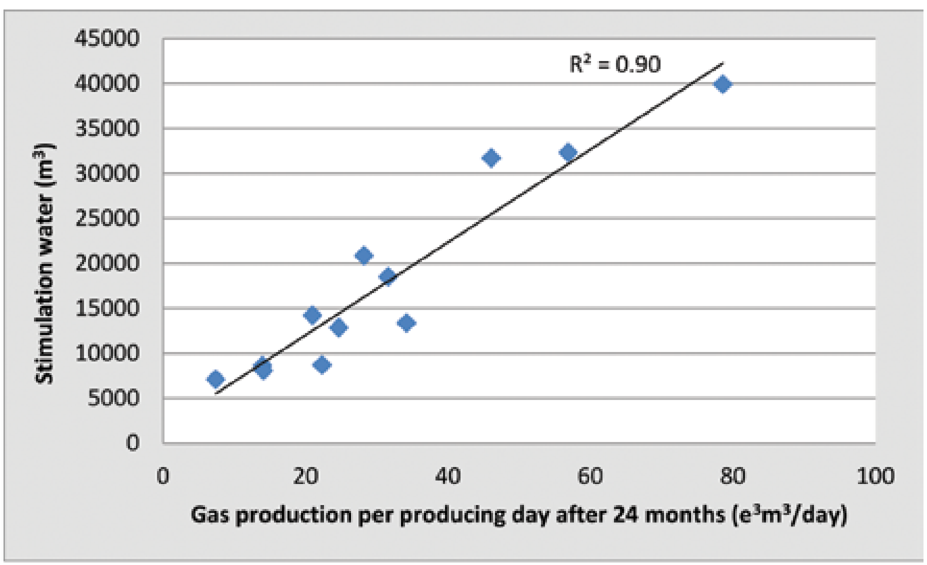

Figure 13. Relationship between stimulation volume for slickwater fractures in the Muskwa–Otter Park formation and later gas production after two years.

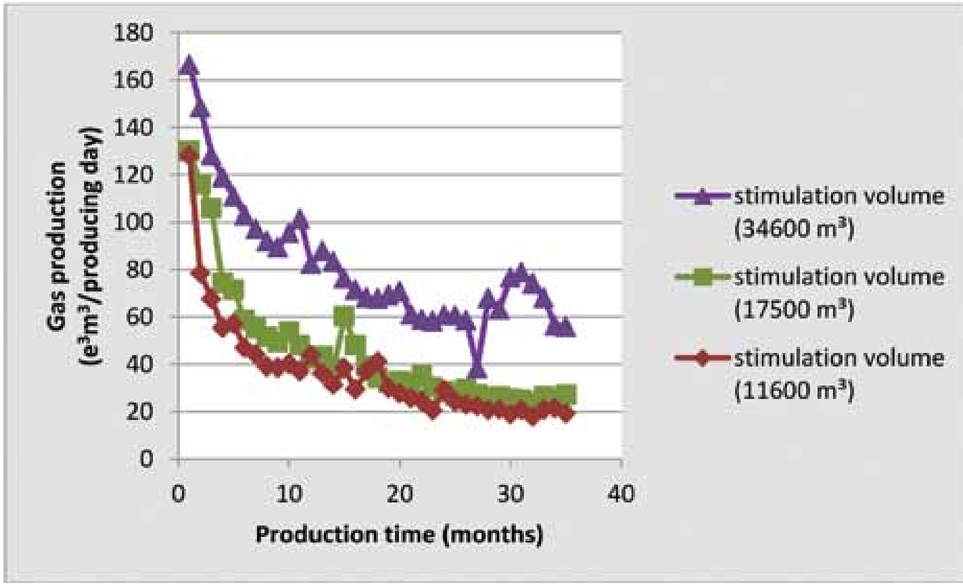

Figure 14. Representative production decline curves in the Muskwa–Otter Park shales for different stimulation volumes. Production curves are grouped according to the initial stimulation volumes as 11 600 m^3, 17 500 m^3 and 34 600 m^3, respectively.

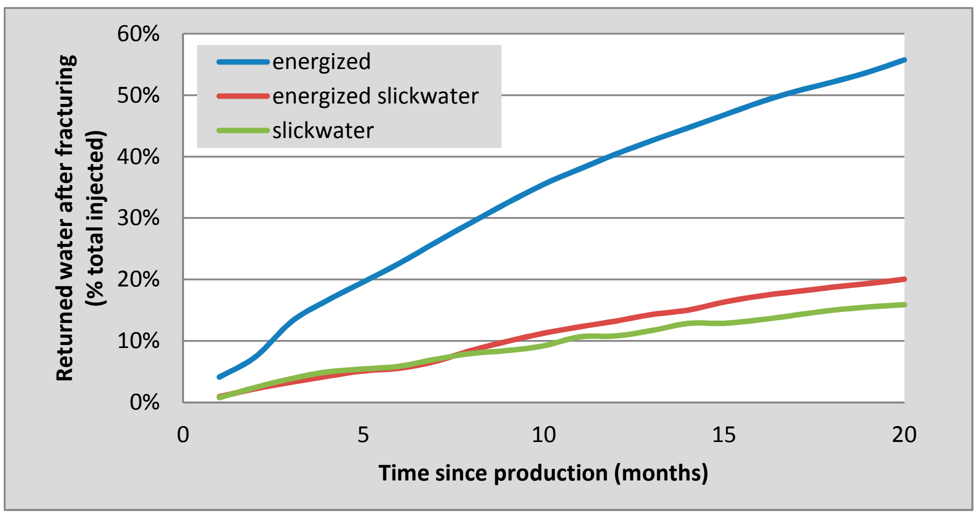

Figure 15. The rate of water return from hydraulic fracturing (as a percentage) over time, as categorized by fracture treatment type.

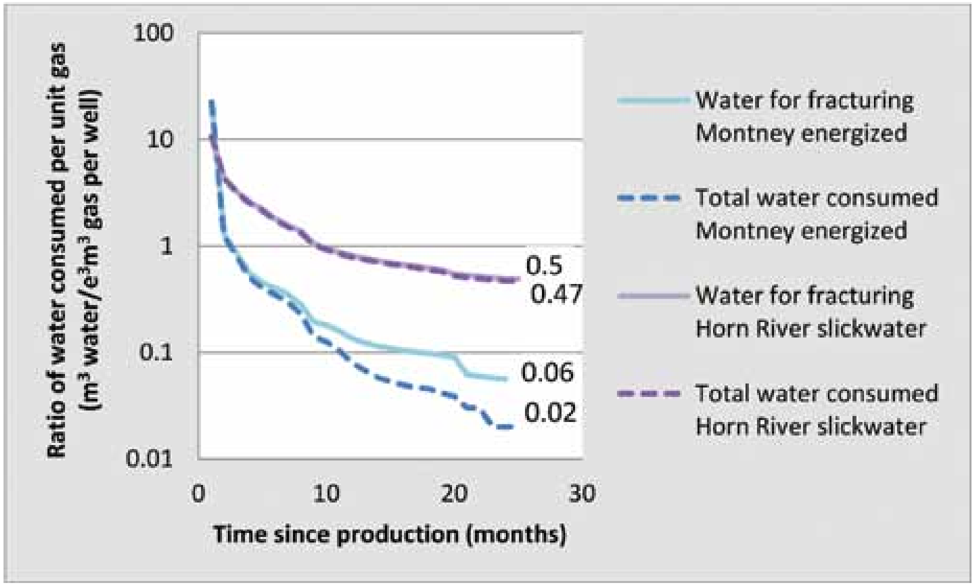

Figure 16. Water consumed to develop every 1000 m^3 gas for both the Montney trend and the Horn River Basin. The total water consumed is the initial water used for fracture stimulation less the return water.

(i.e., energized slickwater treatments) improved recovery slightly to 20%. The volume of return water for energized treatments was significant at 55% after 20 months. Data specific to energized wells in the Montney reveals that returned fluid exceeds 100% of that injected, which means that the returned water in the Montney Formation is a combination of both flowback fluid and produced water.

For the HRB, the ratio of the total water consumed per unit gas produced is not significantly different from the ratio of initial hydraulic fracturing water used for each unit gas produced (Fig. 16). This is because the return volumes are too low to mitigate overall consumption. Conversely, the small amount of water used for fracturing in the Montney (0.06 m^3 per unit gas) is substantially reduced by using return water (0.02 m^3 per unit gas). This metric of consumption becomes moot if saline water is used for fracturing.

DISCUSSION AND IMPLICATIONS

Water usage varies by basin (Fig. 17). The HRB and the Deep Basin have the highest water-use requirements; the Montney Basin has the lowest. This is expected, given the consistent use within each basin of their respective completion methods. Slickwater fractures are used for siliceous shale in the HRB and for sandstone and conglomerate across the Deep Basin (Table 1). By contrast, small amounts of water are needed for the energized fractures used in the softer siltstone and shale in the Montney Formation.

Despite the relatively small multistage hydraulic fracture database and disproportionate number of wells from the Montney Trend, available data from the other major basins were still sufficient to provide useful insight into some general trends in water usage in these basins. Data from the HRB and other more recent plays was limited because activity is more recent there and fracture information has not yet been entered and validated in the IRIS well database.

Montney Trend

Overall water usage for the Montney Trend was 1900 m^3 per well (Table 8). This volume fits well with other estimates in the literature (Dunk, 2010; Burke et al., 2011). This volume is consistent with water use in other basins that employ hydraulic fracturing. Fracture treatments in the Montney are primarily energized CO_2 treatments and generally have low water-use requirements.

The Montney showed trends of increasing the number of fracture stages (Fig. 6), fracture spacing (Fig. 8) and fracture length (Fig. 9); however, no overall correlation was found between gas production and any of these factors. It is unclear as to why this would be the case. Perhaps the production of condensates is driving the process. Subclassification of the data may better reveal trends and relationships.

The last finding of particular relevance to the Montney is the extent to which return water may influence consumption water. Energized wells in the Montney show returns of greater than 50% (Fig. 15). Returned water, if reused, could be an important factor in mitigating water demand for hydraulic fracturing in the Montney.

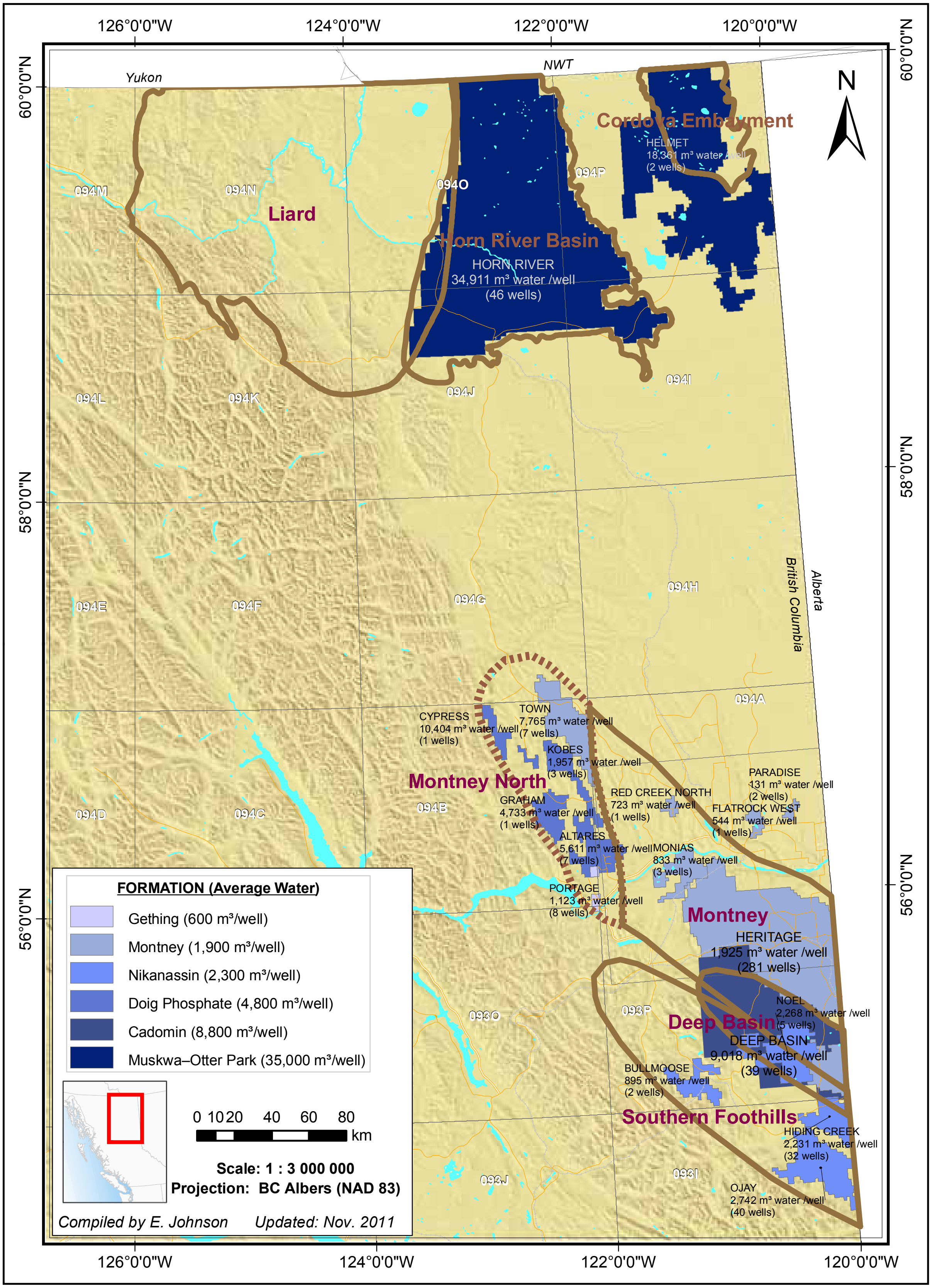

Figure 17. The formations being targeted in the five main basins. The water usage per well has been averaged by multistage wells in that formation and is represented by colours grading from light blue (lowest) to dark blue (highest).

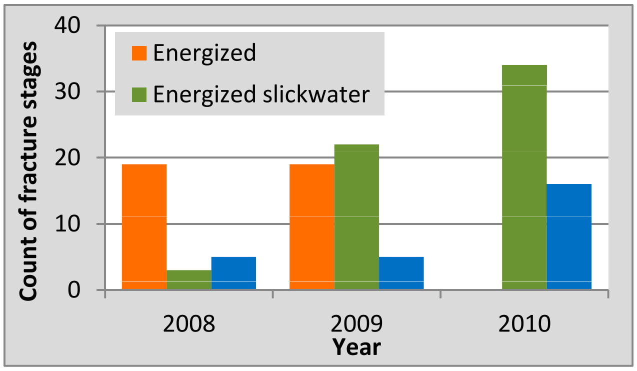

Figure 18. Montney North fracture treatment type as a function of time.

Horn River Basin

Overall water usage for the HRB was 30 000 m^3 per well (Table 8). This estimate is low because the average reflects the average of early wells that used few fractures with much smaller volumes. Still, the volume is an order of magnitude larger than that in the Montney. The primary reason for high water usage in the HRB is that high-volume slickwater treatments are almost exclusively used. Also, operators tend to have significantly more fracture stages per well. The trend in water usage has increased so sharply that average water per well value presented herein seems low.

The cumulative stimulation volume used for multi-stage wells in the HRB outpaced water consumption in the Montney Trend by 3.5:1 in 2010. The current trend for a high volume use in the HRB is expected to escalate because the best production is associated with wells that used the most water (Fig. 13, 14). Stimulation volume of water is a good proxy for stimulated reservoir volume, which means the more water used to fracture, the more gas produced. Further, water usage–related factors such as fracture length, number of completion stages and fracture spacing have not leveled off. Horizontal lengths in the Horn River Basin now extend up to 3 km (Stonehouse, 2011). Improvements in technology are enabling considerably more stages per well. Slickwater wells in the database have up to 28 stages but new OHMS technology allows for 40 to 60 stages per well. Service companies expect to be able to emplace more than 100 stages per well (Chandler, 2011; Themig, 2011).

Return water volumes are not likely to mitigate the need for increased stimulation water in the HRB. The rate of return water from slickwater wells is 17%. This rate of return is considerably less than the 30% indicated by Zelenev et al. (2010) and Burke et al. (2011). As a consequence, the volume of return water from slickwater operations in the HRB is unlikely to have a significant impact on water consumption rates.

The development of saline water resources is a potential source of water for gas-oriented fracturing operations in northeast British Columbia. Saline water can be substituted for freshwater in concentrations up to 100 000 ppm depending on the quality of the friction-reducing agent used (Blauch, 2010; Paktinat et al., 2011). Still, information is required to assess saline aquifer resources in the appropriate basins.

Montney North Trend

Overall, water use for the Montney North Trend was 5900 m^3 per well (Table 8). This value is considerably more than the 1900 m^3 per well determined for the Montney Trend. The reasons for this difference are that producers have different targets (the Doig Phosphate instead of the Nikanassin Group) and the Montney Formation is more shale rich in Montney North. Accordingly, different treatment types (with different water requirements) are needed to develop this region. Inconsistency in the treatment type across the basin may also reflect the fact that companies are still experimenting with treatment approaches in the region. Figure 18 shows the rapid shift in completion methods from energized towards slickwater.

Increasing water demand can be expected for the Montney North Trend as development in the region appears to be leaning towards both slickwater and energized slickwater fracturing. This evolution of treatment type in the Montney North has important implications for future expected water usage in the region because hybrid-energized slickwater treatments use five times the volume of water of energized treatments for every fracture stage (Table 5). Thus, the volume of water required to develop the Montney North could be more than an order of magnitude greater than the Montney Trend, depending on the completion method.

Deep Basin

Overall, water use for the Deep Basin was 9000 m^3 per well (Table 8). This basin has the second highest water usage for wells in northeast British Columbia (Fig. 17). The Cadomin Formation in the Deep Basin is not an unconventional shale gas target. The formation is composed of sandstone and conglomerate and has significantly lower pressures than other formations at similar depths. Given this geology, one would think that energized completions would be the treatment of choice. Instead, the trend in well completions here is towards slickwater fractures (Fig. 5).

The slickwater completions that have occurred in the Cadomin Formation have not been as effective as for those done in the more brittle Muskwa–Otter Park shales. Deep Basin operators use half the water per fracture stage compared to those in the HRB and show lower production rates (Table 8, Fig. 7). Development activity in the Deep Basin has not kept up with that in the HRB.

TABLE 8. AVERAGE WATER CONSUMPTION AND GAS PRODUCTION FOR SEVEN FORMATIONS IN NORTHEAST BRITISH COLUMBIA.

Formation	Region	Water per stage (m^3)	Main treatment type	Stages per well	Average water per wells (m^3)	Initial production rate (e^3m^3/day)	Main operator
MONTNEY	Montney	250	Energized	8	1900	90	Encana
	Montney North	1000	Variable	8	7800		Progress Energy
DOIG PHOSPHATE	Montney North	800	Variable	6	4800	32.4	Talisman Energy, Canbriam Energy
GETHING	Montney	40	Energized	10	400	0.5	Hudson's Hope Gas
	Montney North	90	Variable	12	1000		
		90	Variable	12	1000		
		90	Variable	12	1000		
	Southern Foothills	100	Slickwater	4	400		
MUSKWA–OTTER PARK	Horn River	2000	Slickwater	13	34900	27	Apache Canada
EVIE	Horn River	2100	Slickwater	10	19500	35.6	Stone Mountain Resources, EOG Resources
CADOMIN	Deep Basin	1100	Slickwater	9	8800	130	EnCana
NIKANASSIN	Montney	500	Variable	4	2100	97.5	Conoco Phillips
	Southern Foothills	500	Variable	6	2600		

Other basins

Little well data are available for the Cordova Embayment or the Liard Basin (Fig. 1). The geology of the Muskwa–Otter Park and Evie shales in the Cordova Embayment is similar to the HRB (Fig. 2). As such, one might expect that multistage slickwater fractures will be used in the Cordova Embayment. The Liard Basin is different in that several formations are likely to be drilled. The Besa River Formation contains some lateral equivalent to the HRB shale. The dominant completion method that will be used for development in the Liard is unclear at this time.

The Southern Foothills Nikanassin Group is composed of sandstone, siltstone, shale and coal. It has tight gas potential but is dissimilar from the other basins. The number of fracture stages per well is currently maintained at a low number. The approach to development at present seems somewhat experimental.

CONCLUSIONS

Research was undertaken on the multistage wells developed between 2005 and 2010 in northeast British Columbia. Wells with more than three hydraulic fractures were evaluated in terms of stimulation volume used, proppant required, the number of fractures, types of fractures, production, geographic distribution and geological factors.

Findings showed that water usage varied by basin with strong differences originating from the stimulation treatment method used. In general, the geology of the basin determines fracture treatment. High-volume water use is not limited to multistage fracturing of brittle shale in the HRB; it is also used to develop sandstone and conglomerate in the Deep Basin south of Dawson Creek. Even a small number of slickwater wells can substantially alter the cumulative water usage in a basin far more than a large number of energized wells. Increased stimulation volume greatly increased the estimated ultimate recovery from slickwater wells in the Muskwa–Otter Park shales in the HRB. This is driving water demand in the HRB.

Implications from the research are that water demand can be anticipated regionally through basin geology, treatment style for fracture stimulation and local trends in the numbers of completions per well. High water demand associated with multistage fracturing is not limited to shale basins but includes other geological settings. The location of high-volume wells is important in assessing regional water demand. These wells should be monitored closely because a few wells can make a large impact on cumulative water consumption. Data backlogs for the IRIS database could severely hamper trend analysis and prediction efforts. Water volume per well is dynamic and could rapidly vary by more than an order of magnitude with a subtle shift in technology. Greatly increased water demand is anticipated in the HRB. By extension, high water demand is also anticipated in the Cordova Embayment and Montney North Trend.

RECOMMENDATIONS

- Recommendation 1: Improved access to current well data and ongoing monitoring of well data on a basin-specific basis.[1] Priority to be given to the HRB and Montney North Trend, where water-use trends are escalating. The Montney North Trend should continue to be treated as a separate region from the Montney Trend to elucidate differences in water usage.
- Recommendation 2: Prioritization of research concerning identification of saline water sources for areas such as the HRB and Montney North, where high-volume water fracturing is occurring.
- Recommendation 3: Use of HRB water-usage estimates as a guide to potential water demand for Montney North, the Cordova Embayment, the Deep Basin and Liard regions until more information is known.

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[1] Improved access includes up-to-date input validation of well data.

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