recovery energy environment economy
2011 CSPG CSEG CWLS Convention

Improved Hydraulic Fracture Performance with Energized Fluids: A Montney Example

Lyle H. Burke, P.Eng.
RPS Energy, Calgary, Alberta, Canada
BurkeLy@rpsgroup.com

Grant W. Nevison, P.Eng.
Nevison Consulting Inc., Calgary, Alberta, Canada

Summary

Results from a recently completed study comparing the performance and costs around the use of energized and non-energized fracturing fluids in the Montney formation are presented to illustrate how the choice of fracturing fluids can impact well performance. The results show significant benefit can be achieved from energized fracturing fluids and that their use warrants investigation in other unconventional oil and gas plays. There is illustrated potential for significant oil and gas recovery improvement, plus there is opportunity to reduce fracturing resources at the same time; water consumption, proppant required, injection rates and thereby injection pressures. The potential environmental benefit by considerably lowering water consumption is attractive and may, in itself, justify their use. Energized fracturing treatments can cost more; however, the benefits are shown to far outweigh the incremental costs. The opportunity exists to improve unconventional well fracturing effectiveness and to reduce the resources used in those treatments by including nitrogen or carbon dioxide in the fracturing fluid.

The Montney Opportunity

The Montney Formation is a large unconventional gas reserve within the Western Canadian Sedimentary Basin as in Figure 1. This Triassic member is more than 200 miles long and 175 miles wide with varying reservoir characteristics and quality. It is a hybrid shale-tight gas resource play with the producing horizon found from 3,000 to 8,000 ft deep. Two producing zones exist in the Montney; the Upper Montney, a light brown, blocky siltstone with interlaminated fine-grained sands, and the Lower Montney, a dark grey, dolomitic siltstone, interbedded with shale. Development of this unconventional gas reserve hinges on horizontal well technology with multiple fracture stages placed along the horizontal.

Figure 1: Montney Formation in the Western Canadian Sedimentary Basin

Adapted from: Geologic Atlas of the WCSB, Alberta Geological Survey

The Montney Challenge

It is common to utilize slickwater based hydraulic fracturing treatments as a basis for the development of unconventional oil and gas plays; however, many operators have successfully adopted energized fracturing fluids to maximize production from these challenging wells. Reducing well cost while achieving good completion efficiency is important for continued effective development of the Montney, and indeed all unconventional oil and gas plays. Half-cycle breakeven gas prices can vary widely within the Montney and are reported in the range of \$3.75/Mcf to \$4.75/Mcf[1] based on a well CAPEX range of \$5.0 to \$5.9 CADMM. Horizontal drilling applied with selective stimulation methods are key technologies to recovering these reserves. It is common to stimulate a single well with 5,000,000 gallons of water used to place 5,000,000 pounds of proppant. Friction reduced water referred to as slick-water is often utilized and pumped at injection rates of 100 bpm to create the desired fracture network.

The quantities of water used is of concern as very little of the injected water is usually recovered; recoveries of less than 30% are frequent. Wells frequently perform as if they have much less reservoir contact or a lower effective stimulated reservoir volume than anticipated. Most significant is the often observed lower than anticipated recovery of the gas in place. Whether this is a result of the unrecovered water blocking flow, poor fracture complexity development, fracture growth out of zone, insufficient proppant transport, or over-estimated reservoir properties can be difficult to determine. Regardless of the cause, ineffective fracture stimulation of unconventional reserves is potentially a major industry issue.

Assessing Fracturing Fluids in the Montney

Extensive use of energized fracturing fluids for recovery of unconventional gas is somewhat unique and a study was undertaken by RPS Energy to assess this practice in the Upper Montney formation[2]. The objective of the study was to compare the performance and fracturing costs of wells treated with energized fluids against those treated with non-energized fluids. The study area is within the Dawson region of N.E. British Columbia that includes 650 Montney wells with over 300 horizontal completions from six operators. A 66 horizontal well sample was selected for analysis, of these 60 wells provided data suitable for analysis representing 20% of the 300 horizontal well population. Of the 60 wells, 43 wells were fractured with energized fluids and 17 fractured with non energized fluids. Though an equal sample of energized and non-energized fracture stimulated wells was desired, the well selection method, along with availability of non-energized candidates, resulted in a larger sample set for the energized treated wells. From this sample set, the performance, applied fracturing resources and costs between the energized and non-energized fracture stimulated horizontal wells were assessed. Production data was acquired for each selected well, plus the resources used for hydraulically fracturing both energized and non-energized wells determined. All information was acquired from public records.

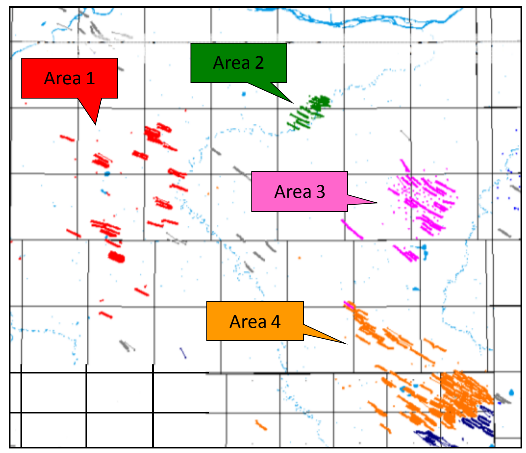

Figure 2: Map of Montney Study Area Well Groupings

Adapted from: RPS Energy GeoScout

Analysis of the data was completed based on a location based grouping of the wells into four primary area groups that coincide with well ownership as shown on Figure 2. Comparing results from single operators as well as operator-to-operator ensured that the impact of differences in drilling and completion practices and reservoir quality was minimized. This area/operator grouping resulted in the exclusion of 9 wells ('Others'), based on outlying locations; fortunately this only included 1 non-energized fractured well. A summary of the resulting area well counts as well as a breakdown of the treatment types are presented in Table 1.

Well Groupings	# Wells in Groupings	# Energized Wells	# Non-Energized Wells	# Insufficient Data Wells
Area 1	24	12	12	0
Area 2	5	3	0	2
Area 3	10	5	4	1
Area 4	15	15	0	0
Others	12	8	1	3
Total	66	43	17	6

Table 1. Well Grouping and Fracture Treatment Type Count

Examination of the well groups shows that non-energized fractured wells were not identified within Area 2 and Area 4. Given the low count of non energized treatments within the field this is not unexpected however this outcome is disappointing as this excludes 18 wells from any type of comparative analysis. The positive aspect is that the wells within Area 1 and Area 3 have a more statistically relevant non-energized fractured well population. In Area 1 this represents 50% of the wells and 45% of the wells in Area 3.

Methodology

For each well within an area grouping, production data is acquired, the reported well lateral length is noted and fracturing parameters of rate, average injection pressure, number of stages, fracturing fluid composition and proppant type and mass are compiled.

The production data is assessed on a well-by-well basis for analysis suitability. The wells are grouped based upon application of energized or non-energized fracture treatments and location is noted and assessed relative to comparative wells. Production from each of the energized or non energized well sets is then averaged separately to generate an average production curve. From the average production of each set, the initial production (IP) and peak rate are identified and noted. The compiled fracturing parameters are averaged for each well set as is the lateral length.

Estimated ultimate recovery from the averaged production data is forecast through decline analysis (DCA) to provide a rate and cumulative recovery profile over a 10 year period. Valko and Ilk et al (Power Law Loss-Ratio) DCA methods have both been demonstrated to be more technically correct for the long transient production periods associated with unconventional production declines than conventional decline analysis that is based on the hyperbolic form of Arp's DCA [3,4,5,6] . Valko DCA was chosen for this study as it is relatively easy to program and apply; the resulting Valko EUR predictions were found to be very comparable to those produced by the more mathematically complex Ilk Power Law Loss-Ratio DCA. The forecast 10 year decline production for each non-energized treated well set is compiled and compared to the corresponding energized treated well set.

Economic analysis between energized and non-energized treated wells includes the incremental value of gas produced with the cost of the fracture treatment. The cost of the fracturing treatment is determined from the average resources applied for the dominant treatment type with value of the resources based on current rates. These costs are based upon the resources used for the treatment types applied, are relevant to the study area, and include equipment travel and materials cartage. Water costs, storage, heating, handling and disposal are excluded mainly due to the variability of reported values. Post-treatment completion costs such as fluid lifting, well flow back and flaring are also excluded.

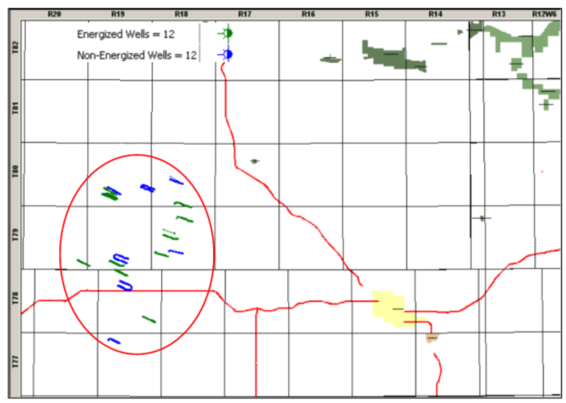

Figure 3: Map of Montney Study Area 1 Well Set

Adapted from: RPS Energy GeoScout

Grouping Area 1 Well Analysis and Results

The Area 1 grouping includes 24 wells of which 12 were fractured with energized fluids and 12 with non-energized fluids. Location and types of fracturing fluid are illustrated on the accompanying diagram Map of Montney Study Area 1 Well Set in Figure 3. Results of the decline analysis of the average production for the energized and non-energized fractured wells are illustrated in the figure Area 1 – Averaged Well 10 Year Valko Decline Analysis as Figure 4. The decline analysis shows gas recovery to 10 years for an energized well at approximately 2.40 Bcf compared to 1.13 Bcf for a non-energized well. This represents an incremental recovery of 1.27 Bcf over 10 years. At marginal gas

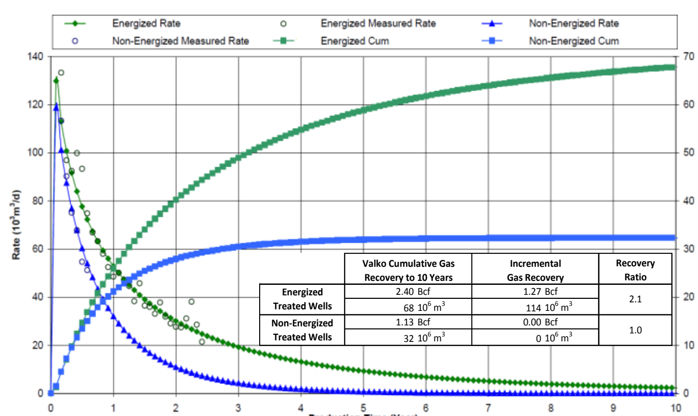

Figure 4: Area 1 – Averaged Well 10 Year Valko Decline Analysis

Adapted from: RPS Energy

prices of $4.00/Mcf, the value of this incremental recovery exceeds $5 million.

A summary of the average parameters for the fracture treatment types completed on the Area 1 wells are presented in Table 2. Only three fracturing types were completed; Slick Water, representing the non-energized fracture treatment and Nitrified Slick Water and CO_2 Foam representing the energized fracture treatments.

	Lateral Length (ft)	Frac Injection Rate (bpm)	Avgerage Injection Pressure (psi)	# Fracturing Stages	Liquid Volume (gal)	Liquid Volume per Stage (gal)	Proppant Mass (lb)	Proppant Mass per Stage (lb)	# Wells Treated
Non-EnergizedWell Averages	**5,807**	**57**	**7,918**	**5**	**1,222,254**	**252,047**	**1,897,035**	**391,326**	12
Energized Well Averages	**6,301**	**39**	**8,400**	**6**	**773,805**	**136,880**	**1,967,644**	**330,137**	12
Nitrified Slick Water Well Averages	6,220	60	8,844	5	1,109,592	225,217	2,125,664	432,498	5
CO2 Foam Well Averages	5,902	27	6,861	7	533,956	73,782	1,854,773	257,022	7

Table 2. Group Area 1 Average Fracturing Parameters by Frac Type

The slick water and nitrified slick water fracture treatments are very similar for rates, number of fracturing stages and water volumes. Injection pressure is seen to be approximately 10% higher for energized treatments and proppant mass is noted slightly higher by about 12%. This compares the twelve slick water fracture treatments to five nitrified slick water treatments.

For the seven CO_2 Foam treatments, most values are significantly lower than the slick water treatments; rate is approximately half, injection pressure is reduced by a quarter and liquid volume is less than half. Total proppant mass is very similar while, on average, two additional stages are used to place the CO_2 Foam treatments. Overall lateral lengths are marginally longer for the energized wells at about 500 feet or 9%. Of note for the CO_2 Foam treatments are the significant reduction in liquid placed in the well, the much reduced injection rate and the expectation for improved proppant transport. Costs for the Slick Water, Nitrified Slick Water and CO_2 Foam fracturing treatments are presented in Table 3.

	Proppant Mass (lb)	Rate (bpm)	Liquid Volume (gal)	Injection Pressure (psi)	Frac Treatment Cost
Slick Water	2,000,000	60	1,214,400	8,000	$1,299,000
Nitrified Slick Water	2,000,000	60	1,108,800	8,900	$1,448,000
CO2 Foam	1,850,000	25	558,096	6,800	$2,024,000

Table 3. Area 1 Fracture Treatment Cost

Assessment of the Area 1 wells show significantly higher gas production from the wells that applied energized fluids. The decline analysis indicated 1.27 Bcf of incremental gas can be recovered; approximately twice as much gas is recovered with energized fracturing fluids compared to non-energized fracturing fluids. Energized fracturing treatments, as expected, are seen to be more expensive. The nitrified slick water treatments are about 10%, and the CO_2 Foam about 55%, more expensive than the non-energized slick water treatment. That relates to approximately $150,000 to $750,000 of incremental cost to recover 1.27 Bcf of additional reserves. On average, each additional Mcf of gas recovered required only $0.35 of incremental fracturing costs.

Grouping Area 3 Well Analysis and Results

The Area 3 grouping includes 9 wells of which 5 were fractured with energized fluids and 4 with non-energized fluids. Location and types of fracturing fluid are illustrated on the accompanying diagram Figure 5: Map of Montney Study Area 3 Well Set. Results of the decline analysis of the average production for the energized and non-energized fractured wells are illustrated in the diagram Figure 6: Area 3 – Averaged Well 10 Year Valko Decline Analysis. The decline analysis shows gas recovery to 10 years for the energized well analysis at approximately 4.70 Bcf compared to 3.0 Bcf for the non-energized well analysis. This represents an incremental recovery of 1.7 Bcf over 10 years. At marginal gas prices of $4.00/Mcf, the value of this incremental

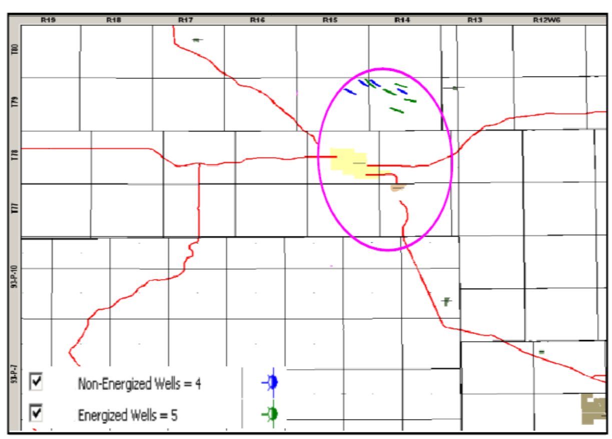

Figure 5: Map of Montney Study Area 3 Well Set

Adapted from: RPS Energy GeoScout

recovery approaches $7 million.

A summary of the average parameters for fracture treatment types completed on the Area 3 wells are presented in Table 4. Only two fracturing types were completed; Gelled Oil representing the non-energized fracture treatment and CO_2 Foam representing the energized fracture treatments. The treatments are very different for virtually all fracturing parameters. Injection rates for the Gelled Frac Oil treatments are approximately half, injection pressures are lower by approximately 10% and proppant mass is lower by 30%. Liquid volume for the CO_2 Foam treatments average about 40% less while the lateral lengths are seen to be approximately 20% longer with two additional stages placed into the wellbore.

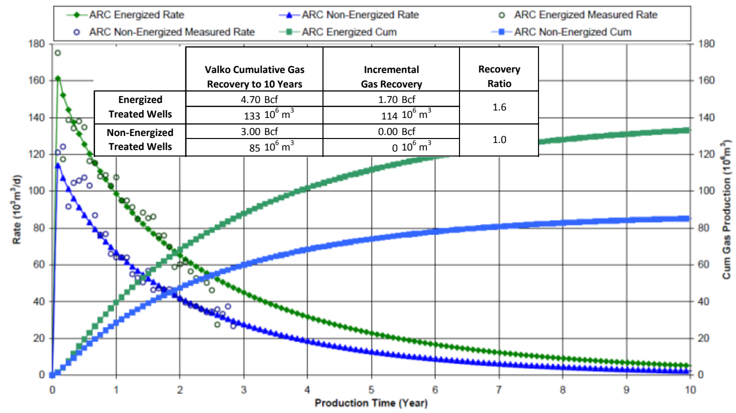

Figure 6: Area 3 - Averaged Well 10 Year Valko Decline Analysis

Adapted from: RPS Energy GeoScout

	Lateral Length (ft)	Frac Injection Rate (bpm)	Avgerage Injection Pressure (psi)	# Fracturing Stages	Liquid Volume (gal)	Liquid Volume per Stage (gal)	Proppant Mass (lb)	Proppant Mass per Stage (lb)	# Wells Treated
Non-EnergizedWell Averages	3,814	11	4,731	5	466,950	93,390	1,298,745	259,749	4
Energized Well Averages	4,675	22	5,262	7	331,483	51,487	1,696,850	268,554	5

Table 4. Group Area 3 Average Fracturing Parameters by Frac Type

Of note for both fluids is that viscosities much above that for slick water are anticipated. This allows reduced liquid volumes and injection rates with the expectation for improved proppant transport. These factors will reduce liquid hold up in the reservoir, minimize fracture height growth and more effectively carry the proppant deeper into the fracture. All are expected to improve well performance. The lesser volume of liquid within the CO_2 Foam fluid plus the gas phase are expected to further improve liquid recoveries and well performance. Costs for the Gelled Frac Oil and CO_2 Foam fracturing treatments are presented in Table 5. For the Gelled Oil treatments, the cost of the frac oil is included with a recovery and resale credit of 75% of the total volume value.

	Proppant Mass (lb)	Rate (bpm)	Liquid Volume (gal)	Injection Pressure (psi)	Frac Treatment Cost
Gelled Frac Oil	1,300,000	11	462,000	5,020	$1,983,000
CO2 Foam	1,600,000	20	202,224	5,235	$1,993,000

Table 5. Area 3 Fracture Treatment Cost

Assessment of the Area 3 wells again show significantly higher gas production from the wells that applied energized fluids. The decline analysis indicated 1.7 Bcf of incremental gas can be recovered; approximately half again as much gas is recovered with energized fracturing fluids compared to non-energized fracturing fluids. Costs between the CO_2 Foam Energized and Gelled Oil fracturing treatments are seen to be virtually the same. As a result the 1.7 Bcf of additional reserves deemed recoverable with the CO_2 Foam treatment does not add incremental fracturing cost. Some portion of the improved production may be claimed with the 30% additional proppant, the 20% longer horizontals lengths and the additional two fracturing stages as applied to the wells using energized fluids. However, the fracture treatment costs for a gelled frac oil treatment will certainly escalate with a 30% increase in treatment size while a 20% longer horizontal with two additional stages is unlikely to generate a 50% plus improvement in recovery on its own.

Well Performance with Fracturing Fluids

Based on the comparative assessment completed on the subject Montney wells in the Dawson Area of N.E. British Columbia, the use of energized fluids is shown to generate significantly improved well performance over those wells fractured with non-energized fluids. On average each well stimulated with energized fluids is shown to potentially recover 2.1 and 1.6 times as much gas as non-energized fracturing treatments for the study areas 1 and 3 respectively.

The study of Area 1 compared the performance of Slick Water against Nitrified Slick Water and CO_2 Foam fracturing treatments. The production analysis showed a 110% incremental recovery improvement of 1.3 Bcf by using energized fluids. Though the treatment costs for the energized fracture treatments were seen to be higher, the value of this incremental recovery far outweighed the additional cost. Of note was the opportunity to reduce the fracturing fluid liquid volumes by over half with using CO_2 Foam treatments rather than Slick Water. This shows the opportunity to improve production while also minimizing environmental impact.

The study of Area 3 compared the performance of Gelled Frac Oil against CO_2 Foam fracturing treatments. The production analysis showed a 60% incremental recovery improvement of 1.7 Bcf by using energized fluid fracturing treatments. The 60% additional recovery from energized fluids in Area 3 compared to the 110% additional recovery in Area 1 implies the Gelled Oil fluid may be a better performing fracturing fluid than Slick Water. Further, though both the Gelled Oil and CO_2 Foam fluids could be considered relatively exotic fracturing fluids for unconventional wells, the CO_2 Foam shows better performance.

Conclusions

1. Based on the comparative assessment completed on the subject Montney wells in the Dawson Area of N.E. British Columbia, the use of energized fluids is shown to generate significantly improved well performance over those wells fractured with non-energized fluids. On average each well stimulated with energized fluids is shown to potentially recover 2.1 and 1.6 times as much gas as non-energized fracturing treatments for the study areas 1 and 3 respectively. The benefits of energized fluids in hydraulic fracturing warrant investigation for all unconventional oil and gas recovery.
2. Beyond additional hydrocarbon recovery, there is opportunity to reduce fracturing resources; water consumption, proppant required, injection rates and injection pressures can be reduced. The potential environmental benefit by considerably lowering water consumption is attractive and may, in itself, justify their use.
3. Energized fracturing treatments can be more costly; however with an efficient treatment program, the benefits can far outweigh the incremental costs.
4. Both nitrogen and carbon dioxide have unique properties and should be examined as possibilities to improve recovery and completion effectiveness in unconventional fracturing.
5. All of the mechanisms available with energized fluids potentially provide benefit of varying degrees. Key aspects include reduced fracture height, improved proppant transport, improved fracture complexity, reduced overall liquid load, immediate relative permeability to gas, reduced surface tension for lower capillary threshold pressures and larger available drawdown pressure to mobilize liquids[7,8,9].

Acknowledgements

The authors are grateful to RPS Energy and Ferus Inc. for supporting the Montney study and this manuscript. We thank P. Hood, P.Geol., R. Kais, and M. Gallup MIT for their technical assistance throughout.

References

[1] Peters &Co. Limited, Energy Update, Montney Update – Greater Dawson Area, March 28, 2011.
[2] RPS Energy, Technical Review of Cryogenic Frac Fluids, Application, Analysis and Cost in the Montney Formation, Dawson Area, Western Canada.
[3] Valko P.P., Assigning Value to Stimulation in the Barnett Shale: a Simultaneous Analysis of 7000 Plus Production Well Histories and Well Completion Records, SPE 119369.
[4] Lee, W.J., Sidle, R.E., Gas Reserves Estimation in Resource Plays, SPE 130102.
[5] McNeil, R., Jeje O., Renaud, A., Application of the Power Law Loss-Ratio Method of Decline Analysis, CIPC Paper 2009-159.
[6] RPS Energy - Technical Review of Cryogenic Frac Fluids, Application, Analysis and Cost in the Montney Formation, Dawson Area, Western Canada.
[7] Hall, M., Kilpatrick, J.E., Surface Microseismic Monitoring of Slick-water and Nitrogen Fracture Stimulations, Arkoma Basin, Oklahoma, SPE 132371.
[8] Wang, F.P., Reed, R.M., Pore Networks and Fluid Flow in Gas Shales, SPE 124253.
[9] Soeder, D.J., Porosity and Permeability of Eastern Devonian Gas Shale, SPE 15213.