Minimize Formation Damage in Water-Sensitive Montney Formation With Energized Fracturing Fluid

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Summary

Slickwater has been widely used for hydraulic fracturing because it is inexpensive and able to carry proppants into the fracture (Schein 2005; Palisch et al. 2010). This fluid, however, is unsuitable for water-sensitive formations, such as the Montney formation. This is because water saturation around the fractures increases, and the clay swells when water leaks into the matrix, both of which hinder the flow of natural gas from the matrix into the fractures. N_2- or CO_2-energized water-based fracturing fluids have been widely used in water-sensitive formations because they can minimize fluid leakoff during fracturing and help achieve higher-load fluid recovery during flowback (Burke and Nevison 2011; Barati and Liang 2014).

In this paper, multiphase numerical simulations are applied to study the formation-damage mitigation in the Montney tight reservoir with energized fracturing fluid. A simulation model is built and history-matched with flowback and early production data gathered from a typical Montney tight gas well. The behavior of the multiphase fluid leakoff and flowback is studied. Sensitivities of the foam quality of the fracturing fluid on the load fluid recovery are analyzed, as is the well productivity after stimulation. Statistical analysis to study the performance of energized fracturing in the water-sensitive Montney formation is conducted on the stimulation and production data of more than 5,000 Montney wells. We found that multiphase fracturing fluid has less dynamic fluid leakoff compared with that of a single-phase fracturing fluid (i.e., water). The major fluid leakoff occurs during the static leakoff period between the end of the stimulation processes and the start of the flowback. The gas phase penetrates deeper and faster into the reservoir matrix compared with the liquid phase, which contributes to the increased flowback volume of the fracturing fluid. Formation damage caused by fracturing-fluid leakoff can affect both early and long-term production. In addition, N_2 foam leads to the highest-load fluid recovery in the Montney formation, which is 1.6 times that of CO_2 foam. This work provides critical insights into understanding the performance of using energized fracturing fluid to mitigate formation damage in tight formations.

Introduction

Well productivity after stimulation can be affected by different factors, such as reservoir permeability, formation pressure, thickness, hydraulic-fracture properties, proppant properties, and load fluid recovery. In water-sensitive tight reservoirs, fluid leakoff is another crucial factor to minimize formation-permeability damage. This paper focuses primarily on the influence of formation damage caused by hydraulic-fracturing fluid retention on well productivity. During the fracturing treatment, the fracturing fluid has direct contact with the formation rock. Because of the significant difference between the fracturing and reservoir pressures, fluid tends to penetrate from the induced fractures into the formation matrix, which is usually referred to as leakoff. The dynamic fluid leakoff during fracturing has substantial impact on the fracture propagation (Adachi et al. 2007; Friehauf 2009). Leakoff models have been proposed in literature to quantify the fluid-leakoff amount (Howard and Fast 1957; Gidley 1989; McGowen and Vitthal 1996). These models use a leakoff coefficient to describe the resistance of the fracture face to fluid filtration. A spurt-loss volume is introduced to quantify the fluid loss before impediment of the filter cake. Laboratory experiments were conducted to measure the foam leakoff and the corresponding reduction of the formation permeability (Harris 1983, 1987). It is shown that foam, as a wall-building material, can reduce the leakoff volume, as well as the formation damage, substantially. The foam rheology, under laminar and turbulent flow conditions, has been studied experimentally; mathematical models were developed to describe the foam rheology while it was flowing in the fracture (Reidenbach et al. 1986). The volume of fluid leakage into the reservoir matrix during this dynamic leakoff stage, however, may not be significant because each stage only lasts for a few hours. In addition, the filter cake formed along the fracture wall and the high fracturing-fluid viscosity both impede the leakoff.

Breaker chemicals are usually injected during the hydraulic-fracturing treatment to aid fracture cleanup (Harris et al. 1997; Montgomery and Smith 2015). These breaker agents degrade filter cake and foam, leading to a reduced fluid viscosity. Because breaker agents are usually coated with slightly permeable materials, their activation is delayed until a few hours after injection. After the filter cake and foam are degraded, the leakoff coefficient is expected to increase significantly, causing substantial fluid invasion (McGowen and Vitthal 1996). Also, the stimulated wells are usually shut in for days, or even weeks, before flowback begins. A large amount of fluid can leak off into the formation, potentially resulting in damage to the matrix permeability.

After degradation, the gas phase in the energized fracturing fluid or foam can leak off into the matrix much faster than does the liquid phase during the static leakoff period. This is because of its low viscosity and high relative permeability. The slippage between the gas and liquid phase causes a pressure increase in the deeper matrix zone that will impede any further fluid invasion. Therefore, N_2-energized fluid, CO_2-energized fluid, N_2 foam, and CO_2 foam have been widely applied, especially in water-sensitive formations. These multiphase energized fracturing fluids are able to help control fluid leakoff and assist load fluid recovery during flowback. A slight difference exists between foam and energized fluids. Technically speaking, a fluid is regarded as foam if the volume percentage of gas to the total fluid is higher than 52%; otherwise, it presents as energized fluid (Ribeiro and Sharma 2012).

This study first presents the use of different types of fracturing fluid in the Montney formation and statistically analyzes the performance of energized fracturing fluid on mitigating formation damage. The multiphase fluid leakoff is numerically simulated, considering gravity segregation, slippage between the two phases, and change in the leakoff coefficient. This work provides better understanding of the mechanisms of energized-fracturing-fluid leakoff and can assist in the design of energized fracturing treatments.

Hydraulic Fracturing in Tight Reservoirs

Because of the advancement of multistage-hydraulic-fracturing techniques, unconventional reservoirs, such as tight/shale

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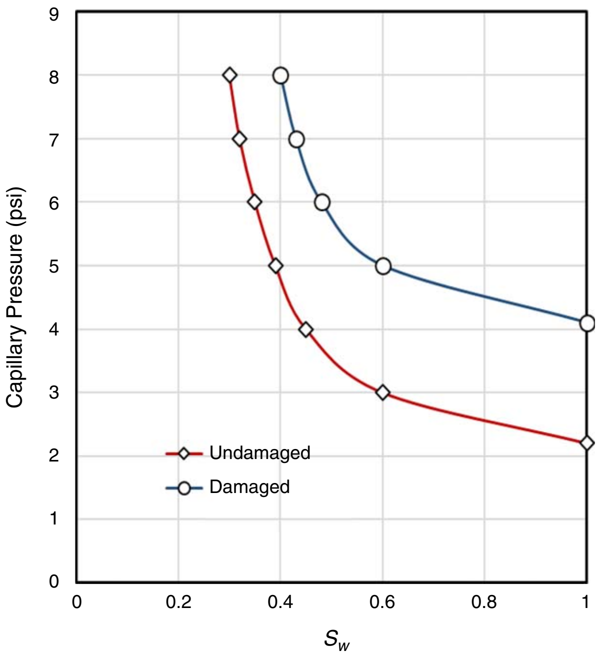

Fig. 1—Effect of damage on the capillary pressure function (Holditch 1979).

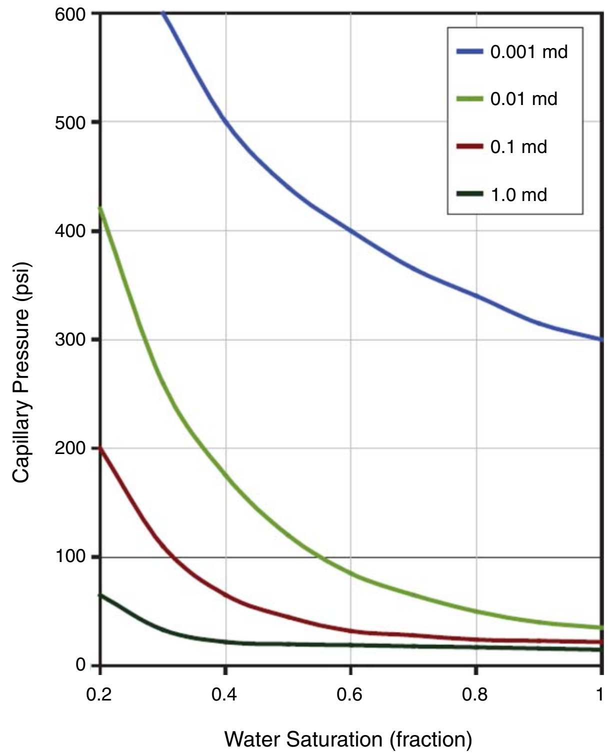

Fig. 2—Effect of capillarity on water saturation (Economides and Martin 2007).

reservoirs and coalbed methane, can be economically developed (Economides and Martin 2007). Hydraulic fracturing creates highly conductive flow pathways for reservoir fluids and greatly increases well productivity, which is crucial for the successful development of ultralow- or low-permeability reservoirs.

Large numbers of tight sandstone reservoirs and shale reservoirs bear a high content of water-sensitive clay (Walls 1982; Slatter et al. 1986; Solano et al. 2012). After exposed to the invaded water, the clay can swell, causing drastic permeability reduction. The fracturing fluid, consequently, needs to be carefully selected. Various types of fracturing fluids have been studied and used in field fracturing treatments. Fracturing fluids currently in use include water-based fluids, oil-based fluids, energized fluids, foams and emulsions, unconventional fluids, and acid fracturing fluids (Economides and Martin 2007). Fracturing fluids need to be selective or customized for each fracturing treatment to avoid formation damage and to obtain high well productivity. Water-based fracturing fluid can imbibe spontaneously into the water-wet formation caused by capillary pressure, potentially leading to formation-permeability damage. Such damage may be reversible or irreversible. If the clay content is high in the reservoir, water invasion will lead to clay swelling and fines migration which reduces the capillary-tube radius (r in Eq. 1), as a result of an increase in capillary pressure, as shown in **Fig. 1.**

$$P_c = \frac{2\sigma\cos\theta}{r}, \quad \text{(1)}$$

where P_c (Pa) is capillary pressure, σ (N/m) is the interfacial tension between the fluids, θ is the contact angle, and r (m) is the capillary-tube radius.

The capillary pressure impedes fracturing-fluid recovery and forms a multiphase flow in the damage zone, leading to a reduction of well productivity after stimulation. If the differential pressure is larger than the capillary pressure, however, the invaded water can be removed gradually. In reservoirs with low clay content, capillary water retention in the damage zone is the most-important reason for well-productivity reduction. This damage is usually remedied with a production-pressure drawdown larger than the capillary pressure. Nevertheless, it may take months for the hydrocarbon-production rate to reach the economic limit.

Water Sensitivity of the Tight Reservoirs. There are two types of water damage to the formation matrix permeability: One is related to the mineralogy and texture of the formation rock, whereas the other is caused by production operation. The first type includes indigenous-clay swelling and particle migration (Hewitt 1963). Clay is widely distributed in sandstone and shale formations. Some categories of clay (e.g., mixed-layer clay, smectites, and illite) can swell when the contacted water-salinity changes, which may happen during well drilling, stimulation, completion, and waterflooding. The swelling clay is able to reduce the pore and throat size, leading to drastic permeability reduction, especially in tight formations. Studies have also shown that the fines migration and plugging contributed by clay swelling cause more-severe formation damage than clay swelling itself (Jones Jr. 1964; Mungan 1965).

Water capillary blocking is another important instigator of formation damage. Subirreducible water saturation is believed to commonly exist in gas reservoirs, which can be caused by dehydration, desiccation, compaction, and diagenetic effects (Bennion et al. 1999; Economides and Martin 2007). In subirreducible water-saturation formations, water can imbibe spontaneously into the formation and be trapped under capillary pressure (Abaa et al. 2013). The increase of water saturation will then decrease the effective permeability of the reservoir oil and/or gas. **Fig. 2** shows the relationship between the capillary pressure and water saturation in reservoirs with different ranges of permeability. Here, the capillary pressure is high when reservoir permeability and water saturation are low, especially when permeability is approximately 0.001 md, which is the case for the Montney formation. High capillary pressure in such reservoirs can lead to a greater aqueous-phase retention caused by capillary imbibition (Economides and Martin 2007). **Fig. 3** illustrates how the increasing water saturation affects the gas relative permeability. It is shown that the increase of the wetting-phase saturation will lead to a dramatic decrease of the nonwetting-phase relative permeability.

Energized Fracturing-Fluid Leakoff. Foam quality is defined as the volumetric percentage of gas phase to the total fluid volume, which usually ranges from 25 to 30% for energized fluids.

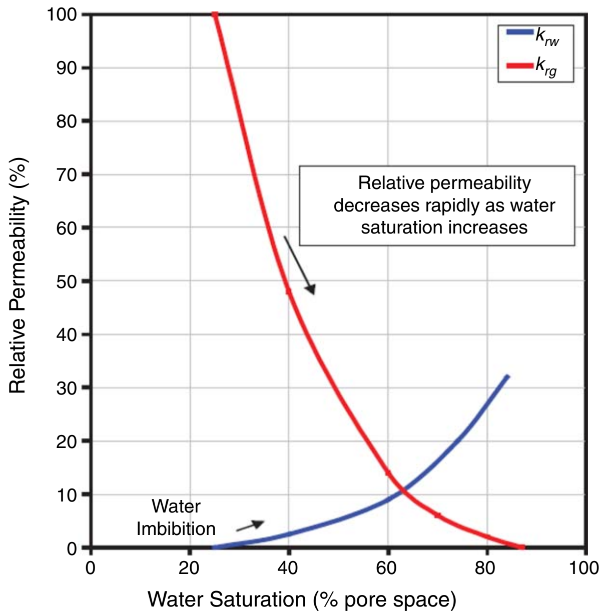

Fig. 3—Effect of water imbibition on relative permeability changes (Economides and Martin 2007).

The common gaseous phase in energized fluid is N_2 or CO_2. N_2 is more popular because it is chemically inert and less expensive than CO_2. After being injected into the fractures, it gradually separates, because of its low density, from the liquid phase, and then leaks off into the formation much faster than the liquid, because of its low viscosity. CO_2 is liquid or supercritical fluid under the pumping condition. Density segregation is not severe in CO_2-energized fluid because the density of CO_2 is close to that of water. CO_2, with its capacity to dissolve in both water and oil, can diffuse into the formation (Economides and Martin 2007).

The leakoff mechanism of the single-phase fracturing fluid (e.g., slickwater) is different from that of the multiphase fracturing fluid (e.g., energized fluid, foam, and emulsion), which usually involves multiphase flow, filter-cake accumulation, and discontinuous phase droplets attaching on the surface of the fracture or filter cake. Several leakoff models have been established to calculate the leakoff rate, where a leakoff coefficient needs to be determined by experiments, by a mini-fracture test, or through estimates from reservoir and fluid properties.

Single-Phase Fluid Leakoff. The most commonly used model for single-phase fluid leakoff is Carter's leakoff model, as shown in Eq. 2 (Howard and Fast 1957). The fluid-leakoff velocity is higher when the formation is first exposed to the fluid and then decreases as the fracturing proceeds. This is consistent with the fact that filter cake builds gradually along the fracture wall; the leakoff velocity decreases as the filter cake becomes thicker:

$$u_l = \frac{C}{\sqrt{t-\tau}}, \quad (2)$$

where u_l (m/s) is leakoff velocity, c $(\mathrm{m}/\sqrt{\mathrm{s}})$ is overall leakoff coefficient including filter-cake effect, τ (s) is the time when the fracture fluid starts to leak off.

Mini-fracture test results, if available, can be used to determine the leakoff coefficient c (Nolte et al. 1993). The fracture geometry is calculated first by theoretical fracture models, such as Perkins-Kern-Nordgren model, Khristianovic-Geertsman model, and radial models (Perkins and Kern 1961; Geertsma and Haafkens 1979; Gidley 1989). Such fracture-geometry models are used to evaluate the pressure-falloff behavior during the mini-fracture test. The single-phase fluid-leakoff coefficient and fluid efficiency can then be obtained with the mini-fracture test results. The leakoff coefficient can also be estimated by reservoir and fluid properties if mini-fracture data are not available. Single-phase fluid leakoff can be described by three different mechanisms, and each mechanism can be accounted for by an individual coefficient, which has been well-discussed in the literature (Friehauf 2009).

Multiphase Fluid Leakoff. When multiphase fluids leak off simultaneously, the phases interfere with each other, adding complexity to the process. Similar to the single-phase fluid leakoff, wall-building is one of the mechanisms that impedes fluid leaking off if filter-cake build material is added. In addition, some distinctive leakoff mechanisms of multiphase fluid include:

- The pores close to the fracture surface are gradually plugged by polymer, impeding the filtrate to flow through.
- Soluble gas is released from invaded fluid as the pressure decreases along the penetration, and the free gas will then impede the liquid leakoff into the matrix.
- Bubbles can be held on the surface of fracture or filter cake (if exists), which will then impede the leakoff of the continuous phase.

Because only a single-phase fluid is usually applied during a mini-fracture test, its results cannot be used to analyze a multiphase fluid leakoff (Woodland and Bell 1989; Nolte et al. 1993). Laboratory experiments on fluid loss remain as more-efficient tools to investigate the multiphase fluid leakoff (Harris 1983, 1987; Friehauf 2009; Ribeiro and Sharma 2012). The results have indicated that foam fracturing fluid has excellent performance on reducing the fluid-leakoff volume into the reservoir matrix; filter cake can form on the fracture surface when wall-building materials, such as hydroxypropyl guar (HPG), are added; bubbles can accumulate on the surface of the fracture or filter cake; foam can leak off into and penetrate through the high-permeability ($\approx$100 md) parts of the cores, while the separated gas and liquid phases can penetrate into the lower-permeability ($<$10 md) portion of the core.

These studies, however, focused on a permeability above 0.1 md. Multiphase fluid leakoff in ultralow-permeability formation has not been comprehensively investigated. In addition, the static fluid leakoff between the end of pumping and the start of flowback is usually ignored. A fracturing stage is usually isolated and shut in while fracturing another stage. Flowback will be conducted after the stimulation of the whole pad has been finished. In some cases, flowback may be delayed for days or weeks after the stimulation is completed. During this period, the breaker chemicals added in the fluid will reduce viscosity and degrade the surfactant. The uniform foam will break into two continuous phases. The leakoff mechanism of this period is much-different from that of the dynamic leakoff.

In this paper, we propose a different theory on multiphase fluid leakoff in ultralow-permeability formations. Dynamic fluid leakoff during pumping has a dramatic impact on fracture propagation (Adachi et al. 2007; Friehauf et al. 2010); however, the static fluid leakoff between the end of the fracturing operation and the start of flowback takes on a more-significant portion of the total fluid leakoff amount, especially in ultralow-permeability formations. Thus, in addition to the aforementioned dynamic leakoff mechanisms, mechanisms of the static leakoff period are considered, which include:

1. When the breaker chemicals become active, both the foam and the filter cake are degraded. Bubbles will rupture, and continuous gas-and-liquid phase will appear. Viscosity of the fracturing fluid is reduced.
2. The gas phase leaks off further into the formation because of its high mobility, and the matrix pore pressure is increased, further hindering the leakoff of the liquid phase.

Case Study: Montney Formation

A successful hydraulic-fracturing treatment is the key to developing the Montney formation because of its ultralow permeability of approximately 0.001 md (Bennion et al. 1999). Mineralogical analysis of Montney core samples has shown that the illite content is approximately 10%, leading to the potential of fines migration, clay swelling, and possible permeability damage (Anderson et al. 2010). In addition, an aqueous-phase retention is another

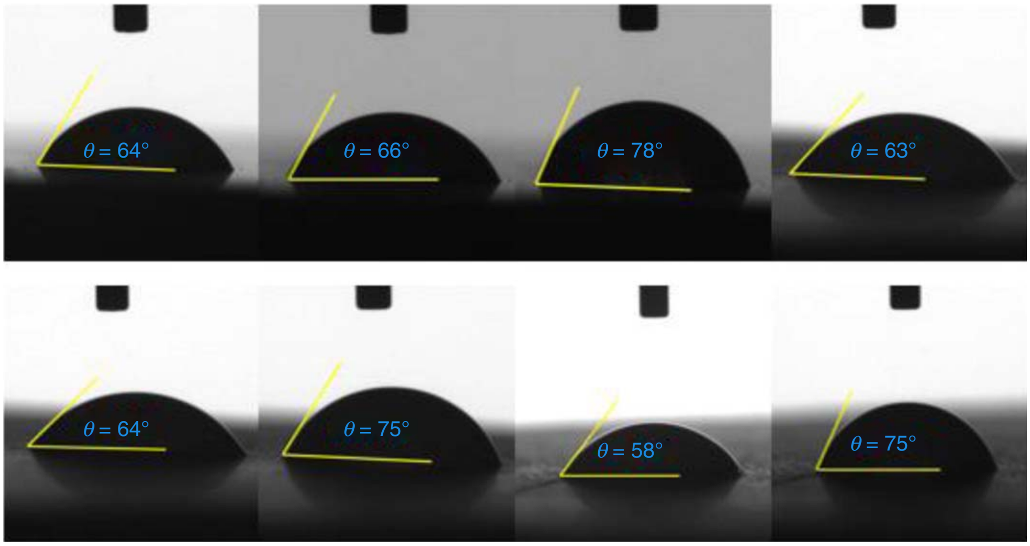

Fig. 4—Water contact angle on Montney core sample shows it is water-wet.

important cause for permeability damage caused by high capillary pressure. The capillary pressure is in the range of 10 to 20 MPa in the Montney formation (Bennion et al. 1999; Hlidek et al. 2012). The percentage of fracturing stimulation by means of energized fluid, including N_2 and CO_2, increases in this formation (Taylor et al. 2010; Burke and Nevison 2011; Reynolds et al. 2014). Statistical analysis shows that energized fractured wells gain a much-higher production than those of the nonenergized fractured wells in the same area (Burke and Nevison 2011).

In our study, the stimulation data and early-production data of more than 5,000 Montney wells are collected and statistically analyzed. The hydraulic-fracturing treatment with different fracturing-fluid types is studied, and its impact on well productivity is analyzed.

A typical tight gas well in Middle Montney is simulated with a multiphase numerical reservoir simulator. The flowback and early production of the well are first history matched, and the static multiphase fluid-leakoff mechanism is then verified with the numerical simulation results. A sensitivity analysis of the fracturing-fluid foam quality on well productivity is also conducted.

Statistical Analysis on Montney Wells. The water/air contact angles have been measured; eight are shown in **Fig. 4.** It can be seen that the water/air contact angles from different Montney core samples were from 58 to 78°, indicating that the study area is water-wet to weakly water-wet. The samples are also characterized with a relatively high clay content and a permeability as low as 0.001 md. The core is sensitive to water invasion, which can cause reduction in both the absolute permeability and the hydrocarbon effective permeability. Oil-based fracturing fluid is widely used in the Montney wells because it affords the least damage to the formation. Nitrogen foam and nitrogen-energized fluid are also intensively adopted. The Montney formation is a combination of the dry-gas reservoir, gradually transitioning to a gas/condensate and oil reservoir. To minimize the influence of reservoir-fluid types on our study, only gas wells were selected. All the wells are horizontal with multistage hydraulic fractures. The wells with abnormal treatment and completion records, such as years' long shut-in periods or too many failed stages, are excluded from our analysis. The data collected from each well include stimulation operational data, including hydraulic-fracturing type, fracturing-fluid type and amount, energizing-agent type and amount, proppant amount, actual stages achieved, completion cost, flowback data, and production data of the first 18 months. The fracturing-fluid-type use percentage in Montney is calculated on the basis of well counts of each fracturing-fluid type, as shown in **Fig. 5.** It is evident that 88% of the Montney wells are stimulated with either an oil-based or energized water-based fracturing fluid. This paper focuses on formation-permeability damage caused by water invasion; thus, only water-based fracturing fluids are studied. Unless stated otherwise, all of the fracturing fluids mentioned in this paper are water-based types.

Nitrogen is chemically inert and able to form a foam more stable compared with that of carbon dioxide. It is also easily accessible and less costly than CO_2 foam. Thus, 59% of the wells adopt N_2 foam and N_2-energized fluid as fracturing fluids. The average completion cost of the hydraulic-fracturing treatment with different fracturing fluids is also evaluated. The completion costs include those related to fracturing fluid, proppants, chemical additives, and equipment. The total cost was averaged to each fracturing stage to be comparable among different wells. Statistical data show that N_2/water system (N_2-energized or N_2 foam depending on the foam quality) is the most-economic among all the water-based-fracturing-fluid systems. It costs approximately 1/3 to 1/2 of that of the CO_2/water system and even less than that of slickwater (labeled as nonenergized), as shown in **Fig. 6.** The load fluid-recovery factor is calculated and grouped according to their fracturing-fluid types. The load fluid-recovery factor of each group is then fitted with normal distribution, whereas the outlier data points are eliminated. **Fig. 7** shows the statistical load fluid-recovery factor of different fracturing fluids used in Montney. It can be seen that N_2 foam has the highest median-load fluid recovery (32.0%), followed by binary-energized (CO_2/N_2-water) (27.2%), CO_2-energized (26.7%), and N_2-energized fluid (23.1%). The load fluid-recovery factor of N_2 foam is approximately 1.6 times that of CO_2 foam. Two possible reasons for this phenomenon are (1) CO_2 creates a low-pH environment that makes the foam system unstable and (2) CO_2 has a higher solubility in water and oil than N_2. The CO_2 diffusion reduces gas volume, thus impeding flowback recovery.

To study the influence of the load fluid-recovery factor on both early and long-term production, the load recovery factor is divided into three levels: low (<10%), medium (10%–40%), and high (>40%). The cumulative production for the first six months (1–6 months), for the second six months (7–12 months), and for the third six months (13–18 months) for each level of load fluid-recovery factor is presented in **Fig. 8.** It is evident that the load fluid-recovery factor can greatly affect productivity during the early-production period. A higher-load fluid-recovery factor will generally lead to a higher production in the first 6 months. For the productivity of 12 to 18 months, the medium and high load fluid-recovery groups have higher median productivity than the low fluid-recovery group; the increasing trend, however, is not evident. It is revealed that a higher load fluid-recovery factor will lead to a higher production, with the trend more significant in the

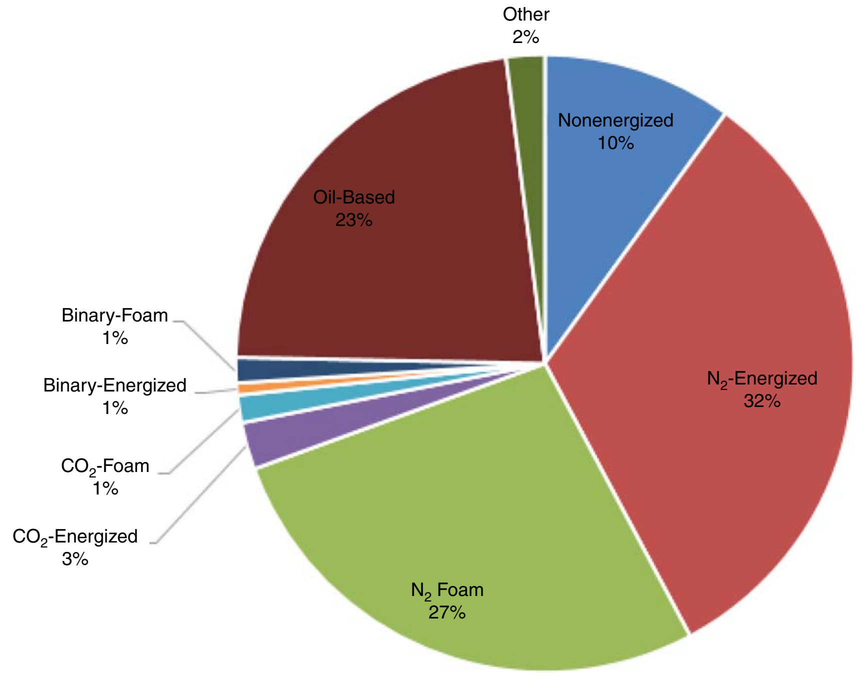

Fig. 5—Fracturing-fluid-type percentage in Montney on the basis of the data of 5,826 wells from 1975 to 2015 (Data provided by the Canadian Discovery Ltd.'s Well Completions and Frac Database).

first 6 months. The production difference between the high and low levels of load fluid-recovery wells in the first 6 months is approximately 42%, and 20% for the third 6 months. In addition, load fluid recovery (or formation damage caused by hydraulic fracturing) has the most-substantial impact on early production, with residual effects during the long term. The formation damage will diminish, however, as the invasion water is gradually removed.

Numerical Simulation of a Montney Tight Gas Well. The components of a typical fracturing-fluid system used in this area are given in **Table 1.** During the injection period, foam is generated and stabilized by various foamer agents and stabilizers. The stimulation of one stage is usually finished within 1 and 2 hours. The foam degradation during this short period is minimal and can be neglected. In addition, the foam leakoff experiment has shown that the foam fracturing system is a wall-building type of fluid, and the leakoff amount of foam is very limited (Harris 1985, 1989). The delayed-release breaker is pumped during the fracturing operation, and will become effective in 7 to 10 hours after the injection, depending on the downhole temperature and the specific breaker chemical type. The breakers can degrade filter cake and foam efficiently; *t* both gas and water phase will then become continuous. The multiphase gravity segregation and leakoff mechanisms have been considered in this work. The pumping schedule includes a proppant-free pad to start fracturing, followed by a proppant-laden N_2/water foam and, finally, a stage of flush fluid. The average fluids and proppant amount pumped for each stage of the study well are listed in **Table 2.** The simulation is for a single stage of the fracturing but can be scaled up to the well level by multiplying the results by 27 stages. The sketch of the stimulation job and simulation reservoir area is shown in **Fig. 9.**

The stimulated well was shut in for 38 days after fracturing operations, followed by 30 days of flowback. The well was shut in again for 67 days before production. The static multiphase- fluid leaksoff during the shut-in period, after stimulation, are numerically simulated. During the static leakoff period, the filter cake and foam degrade because of the activation of injected delayed-

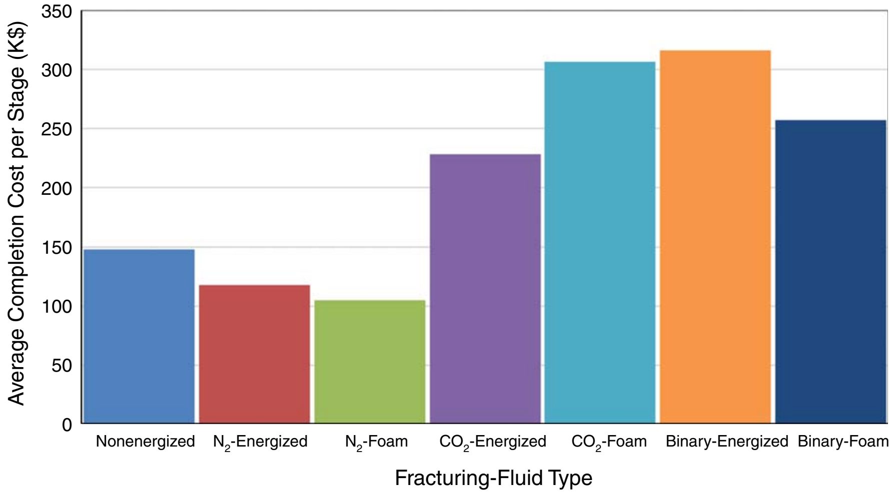

Fig. 6—Average completion cost per stage of water-based fracturing in Montney (Data provided by the Canadian Discovery Ltd.'s Well Completions and Frac Database).

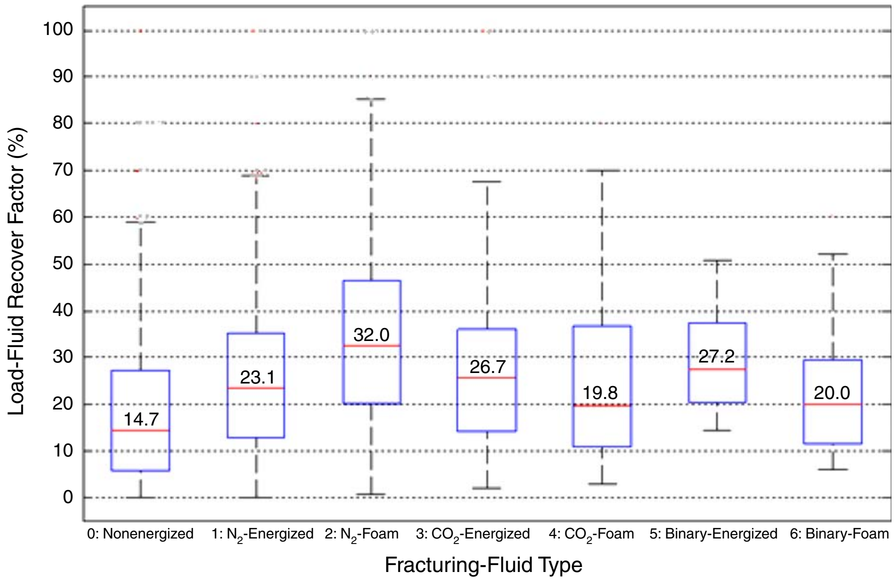

Fig. 7—Load fluid-recovery factor for different water-based fracturing fluid in Montney (Data provided by the Canadian Discovery Ltd.'s Well Completions and Frac Database).

release chemical breakers. The effect of gravity segregation and the slippage between the gas and liquid phases are considered in this study. The flowback and early production are history matched for further analysis, as seen in **Fig. 10.**

After completion, the breaker agent becomes effective. The fluid viscosity is reduced, the foam becomes unstable, and the leakoff-hindering filter cake is degraded. Both the gas and liquid phases become continuous. Gravity segregation will happen because of the density difference: Water will accumulate at the lower part of the fracture, and gas will accumulate at the higher part of the fracture. Fig. 10 depicts the water saturation in the matrix adjacent to the top and bottom of the fracture. It can be seen that water can penetrate nearly 2 m into the formation matrix along the fracture. This is mainly because of the ultralow formation matrix permeability. The water invasion is more-severe in the matrix near the bottom of the fracture than that of the top part. Water saturation near the bottom can reach as high as 95%, while remaining below 35% near the top part of the fracture. Because of gravity segregation, gas accumulates at the top fracture, which greatly mitigates water invasion into the matrix. In addition, water saturation near the top part of the fracture reaches a highest value at the location 0.5 m away from the fracture. This is because the gravity segregation of the two phases happens simultaneously as they leak off into formation.

A sensitivity analysis is conducted to study the influence of different foam qualities on water invasion and well post-

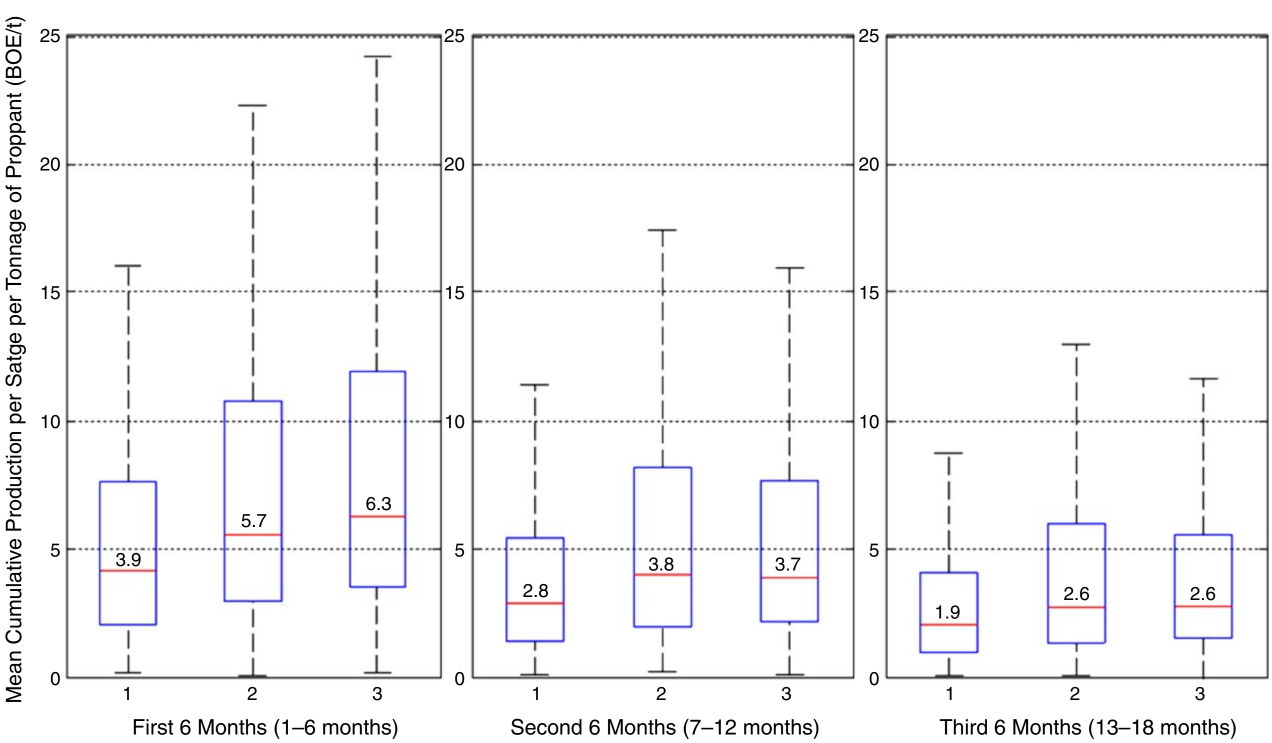

Fig. 8—Impact of aqueous-load fluid-recovery factor on well production, 1-low-load fluid recovery < 10%; 2-medium-load fluid recovery 10 to 40%; and 3-high-load fluid recovery > 40% (Data provided by the Canadian Discovery Ltd.'s Well Completions and Frac Database).

Water	Base Fluid
Nitrogen	Energizer
Proppant	Keep fracture open
Surface tension Reducer	Reduce surface tension
Crosslinker	Increase fluid viscosity
Foamer	Generate foam
Gelling agent	Increase fluid viscosity
Biocide	Inhibit biological degradation
Delayed release Breaker	Degrade filter cake and foamed fluid, becomes effective in hours
Breaker	Degrade filter cake and foamed fluid

Table 1—Fracturing-fluid components and functions.

Nitrogen	104,122.41	std m^3/stage
Water	203.16	m^3/stage
Proppant	115.22	tons/stage
Well spacing	134	m
Fracture spacing	77	m
Formation thickness	20	m
Stages	27	
Initial reservoir pressure	33	MPa
Fracturing pressure	60	MPa
Average reservoir permeability	0.0012	md

Table 2—Stimulation data and reservoir basic properties.

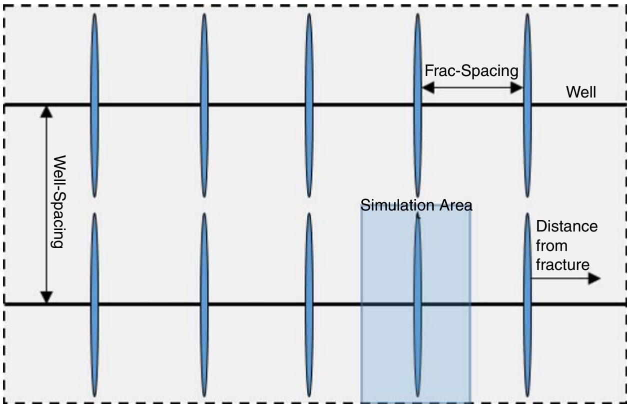

Fig. 9—Stimulation sketch and simulation area.

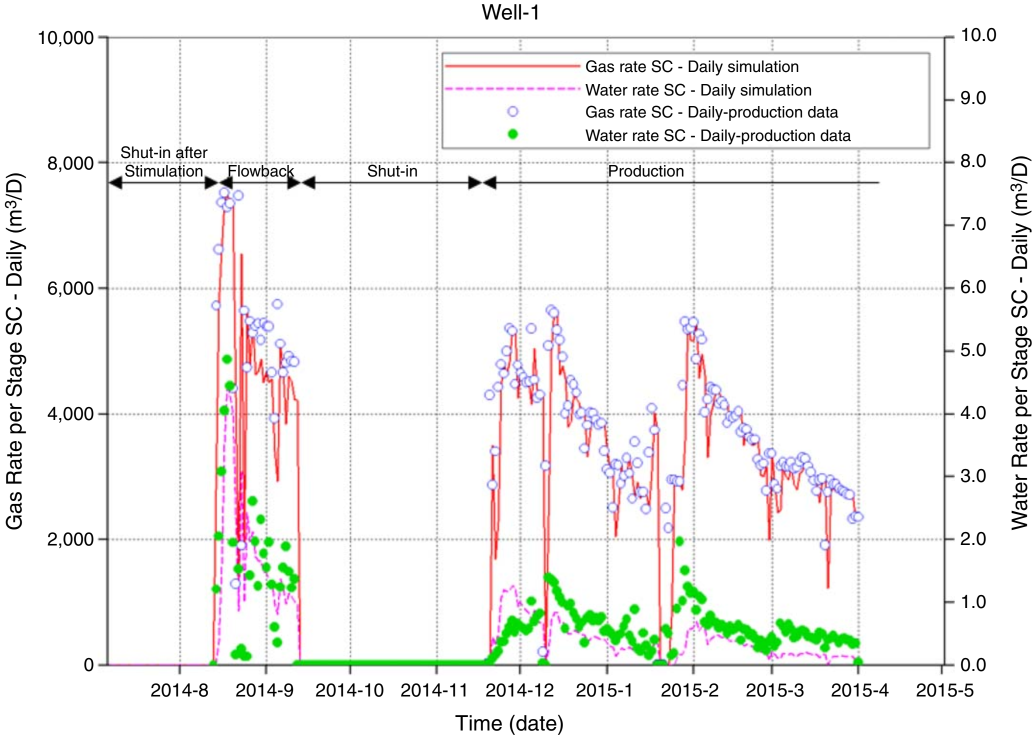

Fig. 10—Impact of foam quality of fracturing fluid on cumulative production.

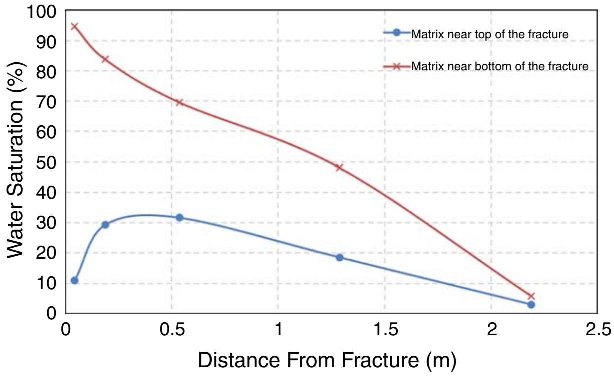

Fig. 11—History matching of a typical N_2-energized fractured well in Montney.

stimulation productivity. **Fig. 11** shows the evolution of pressure at the first, 10th, 20th, and 37th day in the near fracture area for cases with different foam quality. Results show that pressure drops significantly in the invasion waterfront area (between 1.2 and 2.6 m away from the fracture) for the low-foam-quality fracturing fluid (e.g., 5%), especially 10 days after well shut-in time. No rapid pressure change occurs for the cases of high-foam quality (e.g., 75 and 95%). Fracturing water invasion is motivated by both the capillary pressure in the water-wet formation and the pressure gradient. The pressure gradient is more pronounced because of its larger value compared with capillary pressure. Thus, water invasion is more severe in the scenario of low-foam-quality fracturing fluid than that of the high-foam-quality fracturing fluid. Moreover, gas from the high-foam-quality fluid penetrates deeper into the matrix, represented by a higher pressure than that of the low-foam-quality fluid. The higher pressure in the deep matrix can assist invasion water to flow back and clean up the fracturing fluid. The initial flow rate and cumulative production for different foam-quality scenarios are plotted in **Figs. 12, 13, and 14.** The foam quality of fracturing fluid has a dramatic impact on the initial production rate. High-foam-quality fluid leads to a minor formation-permeability damage and increases pressure near the fracture, both of which result in a higher initial gas productivity. The long-term production results indicate that a 5% foam quality can lead to more than a 12% reduction of cumulative production for the first year. This reduction increases to

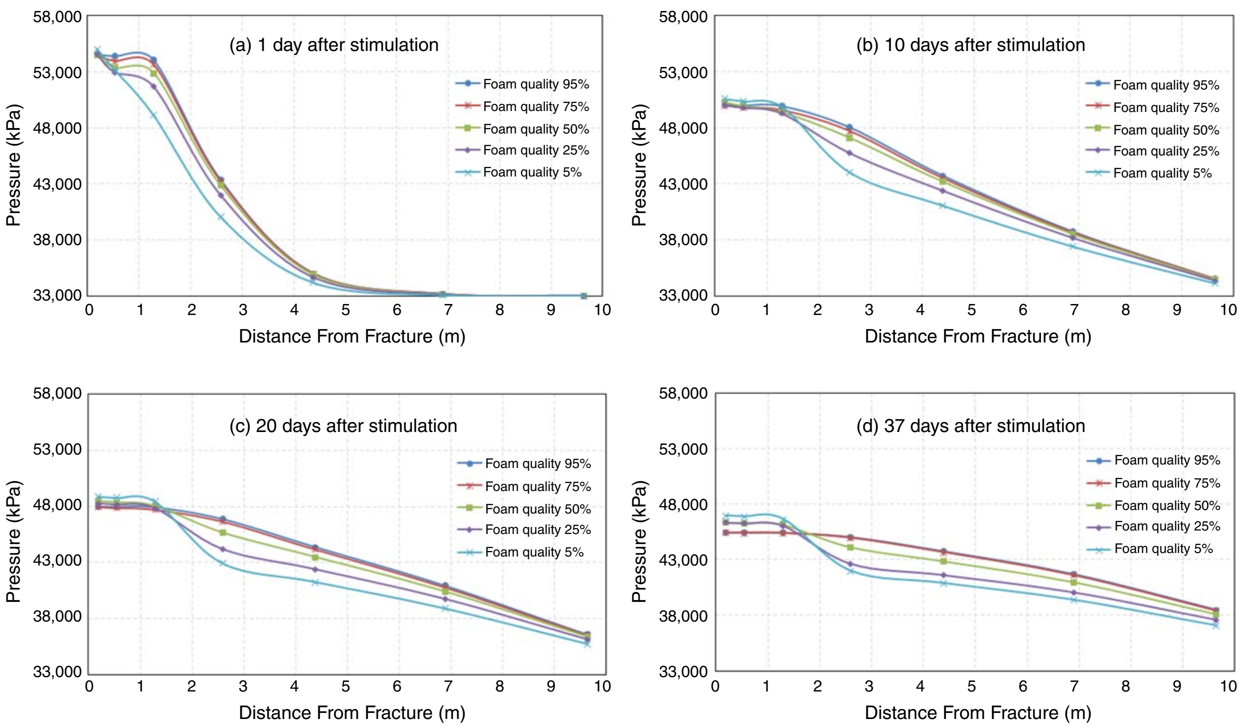

Fig. 12—Gravity segregation before flowback (S_{wc} = 0.03; foam quality is 46%).

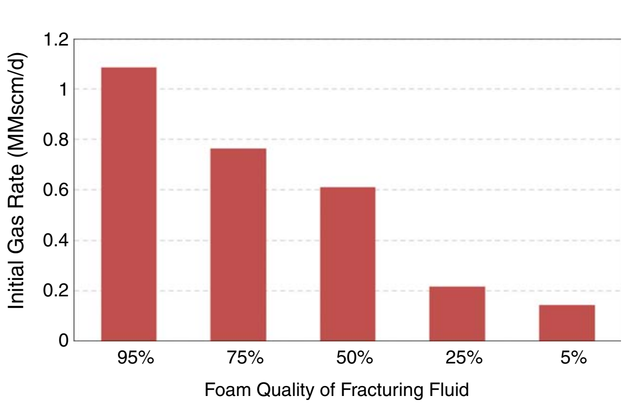

Fig. 13—Evolution of pressure distribution near fracture with different-foam-quality fracturing fluid.

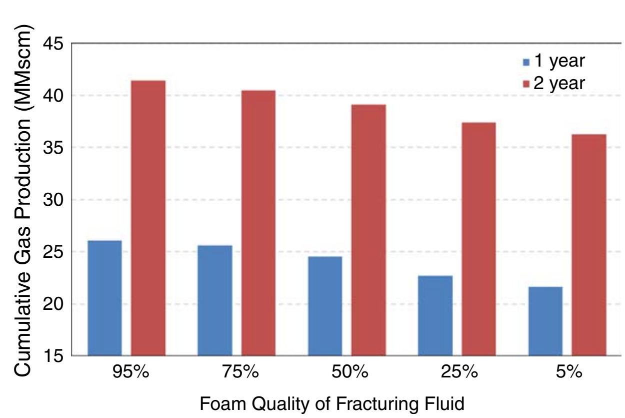

Fig. 14—Impact of foam quality of fracturing fluid on initial production rate.

more than 17% for the first 2 years, compared with the stimulation with 95%-foam-quality fluid, as shown in Fig. 14.

The study found that formation damage caused by fracturing-fluid leakoff not only influences early production, but has a lasting impact on well performance. Energized fracturing fluid can effectively reduce the fracturing-fluid invasion and enhance stimulation performance in both short-term and long-term production.

Conclusion

In this study, the mechanisms of single-phase and multiphase fracturing-fluid leakoff and their influence on fracturing-fluid flowback and production are studied. A field case in the Montney formation is simulated to study the fluid leakoff and flowback. The sensitivity of fracturing-fluid foam quality on well productivity after stimulation is studied. Production data of more than 5,000 wells in the Montney formation are analyzed to compare the performance of different fracturing fluids and the impact of load fluid-recovery factor on production. The following conclusions are drawn:

- The water invasion is more severe in the matrix near the bottom of the fracture than at the top portion of the fracture. Gravity segregation also causes gas accumulation at the top of the fracture, which mitigates water invasion into the matrix.
- When high-foam-quality fracturing fluid is adopted, the gas phase penetrates deeper and faster into the matrix because of its higher mobility in porous media. This hinders further water invasion and assists the flowback of the liquid phase.
- Formation damage, caused by fracturing-fluid leakoff, not only will affect early production, but also will have a long-term impact on well performance. Energized fracturing fluid can effectively reduce the water invasion, enhancing both early and long-term production.
- In the Montney formation, N_2 foam leads to a highest-load fluid recovery, followed by binary-energized, CO_2-energized, and N_2-energized fluids. The load fluid-recovery factor of N_2 foam is approximately 1.6 times of that of CO_2 foam.

Nomenclature

P_c = capillary pressure, Pa
σ = interfacial tension, N/m
θ = contact angle, degree
r = capillary-tube radius, m
u_l = leakoff velocity, m/s
c = overall leakoff coefficient, $\mathrm{m}/\sqrt{\mathrm{s}}$
τ = leakoff time of fracturing fluid, s

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