



Water footprint of hydraulic fracturing in Northeastern British Columbia, Canada

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Abstract

The method of hydraulic fracturing used to exploit unconventional shale gas has raised public concerns over the volumes of freshwater that are extracted for injection operations as well as the volumes of wastewater generated as a by-product of gas production. Using data from the British Columbia Oil and Gas Commission, this paper examines the volumes of produced and injected water from hydraulically fractured gas wells in Northeastern British Columbia. The two major producing shale gas basins in the province are the Montney and the Horn River. In this study, these are divided into several sub-basins based on existing geological and reservoir engineering applications. For each sub-basin the average volumes of wastewater- and injected water per well are calculated and then normalized to cumulative gas production. Ratios of injected water: gas production and wastewater: gas production are then applied to estimated volumes of remaining gas reserves in each sub-basin in order to calculate a total water footprint of future exploitation. These extrapolated water footprints were further elaborated into three scenarios of wastewater recycling rates: 0, 40, and 100% re-use. This study also compares the quality and quantity of wastewater produced from hydraulically fractured wells to their conventional counterparts in the province. Based on these calculations, the total future freshwater withdrawal and wastewater production volumes for all basins range from 1.65 to 3 billion, and 0 to 1.35 billion cubic metres, respectively. Volumes of freshwater withdrawal are relatively modest compared to other industries when considering the size of Northeastern British Columbia and the time-scale of extraction. In general, hydraulically fractured wells in Northeastern British Columbia produce volumes of wastewater that are equal to or lower than those required for injection. Unconventional gas wells often produce far less wastewater than their conventional counterparts.

Keywords Shale gas · Hydraulic fracturing · Northeastern British Columbia · Freshwater withdrawal · Produced water · Water footprint

Introduction

Production of natural gas from tight shale reservoirs (shale gas) has been steadily increasing worldwide since 2005 and is projected to constitute 30% of worldwide gas production by 2040 (US EIA 2015). For many countries, the possibility of shale gas production thanks to new exploitation techniques presents a pathway towards energy independence in the near future (US EIA 2015). Significant reserves of shale gas exist in Canada, where nine gas-bearing shale formations

are spread out over five provinces and two territories (Rivard et al. 2014). However, the method used to exploit shale gas has raised some environmental concerns, particularly the possible cross-contamination of aquifers and surface waters either from hydraulic fracturing of the shale (Wisen et al. 2019a, b) or from disposal at depth of the wastewater thus produced. As a consequence, a moratorium has been placed on shale gas development in three Canadian provinces (Québec, New Brunswick and Nova Scotia) and in several countries including France and Germany.

Shale gas is exploited through the combined techniques of horizontal drilling and multi-stage hydraulic fracturing (“fracking”). Fracking is the process by which perforated sections of a horizontal wellbore are sequentially injected with high volumes of water and sand, in order to create and prop open a fracture network. This created fracture network increases the bulk permeability of the shale, allowing the

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flow and production of hydrocarbons that would otherwise remain trapped in the rock matrix. Exploited shale gas reservoirs are typically found at depths greater than a kilometre. Shale gas is considered an example of *unconventional gas* in that it relies upon an enhanced stimulation technique (i.e. fracking) in order to generate economic production. *Conventional gas*, on the other hand, does not require any stimulation to make economic amounts of gas flow to the surface (Johnson and Johnson 2012). Figure 1 illustrates the cycles of water injection and production for conventional and hydraulically fractured wells.

In order to maximize the effectiveness of fracturing, prior to injection a number of chemical additives are mixed in with the water along with the sand proppant. These chemicals include viscosity and pH adjusters, friction reducers, corrosion and scale inhibitors, surfactants, gelling agents and clay stabilizers to inhibit clay flocculation (Jackson et al. 2013). Some of this hazardous water will flow back up the wellhead (flowback water) along with formation brines (produced water) during production of the well (Vengosh et al. 2014; Lutz et al. 2013). Produced water from shale gas is characterized by high concentrations of toxic elements such as barium, strontium and radioactive radium. Additionally, as with most conventional reservoirs, produced water is highly saline and often contains dissolved organic compounds (Vengosh et al. 2014). These toxic and radioactive elements typically show a direct correlation with salinity (Vengosh

et al. 2014). Flowback and produced water are sometimes collectively termed flowback-produced (FP) water (Scanlon et al. 2016) or more generally, fracking “wastewater” (Lutz et al. 2013). Typically, the salinity of fracking wastewater increases over time as the chemistry shifts from flowback to brine-dominated (Vengosh et al. 2014).

The generation and handling of wastewater from shale gas present an environmental challenge and possible threat to freshwater resources located in proximity to hydraulic fracturing operations. Shale gas FP waters can be managed either through reuse in subsequent hydraulic fracturing operations or by permanent disposal (US EPA 2016). Due to their high salinity, FP waters are generally less effective at hydraulic fracturing than freshwaters and hence require more treatment and additives before they can be reused for subsequent hydraulic fracturing operations (US EPA 2016; CCA 2014). Similarly, treatment for release into surface waters is a complicated and costly process. In some cases, this treatment option has been found to be inefficient at completely eradicating the geochemical signature of FP waters below safe drinking standard thresholds (Warner et al. 2012). As a result, deep disposal is typically the most feasible and cost-effective method for managing FP waters from shale gas operations (US EPA 2016).

Deep disposal is the process by which wastewater is injected through a disposal well into deep saline aquifers. Deep saline aquifers are permeable formations located at

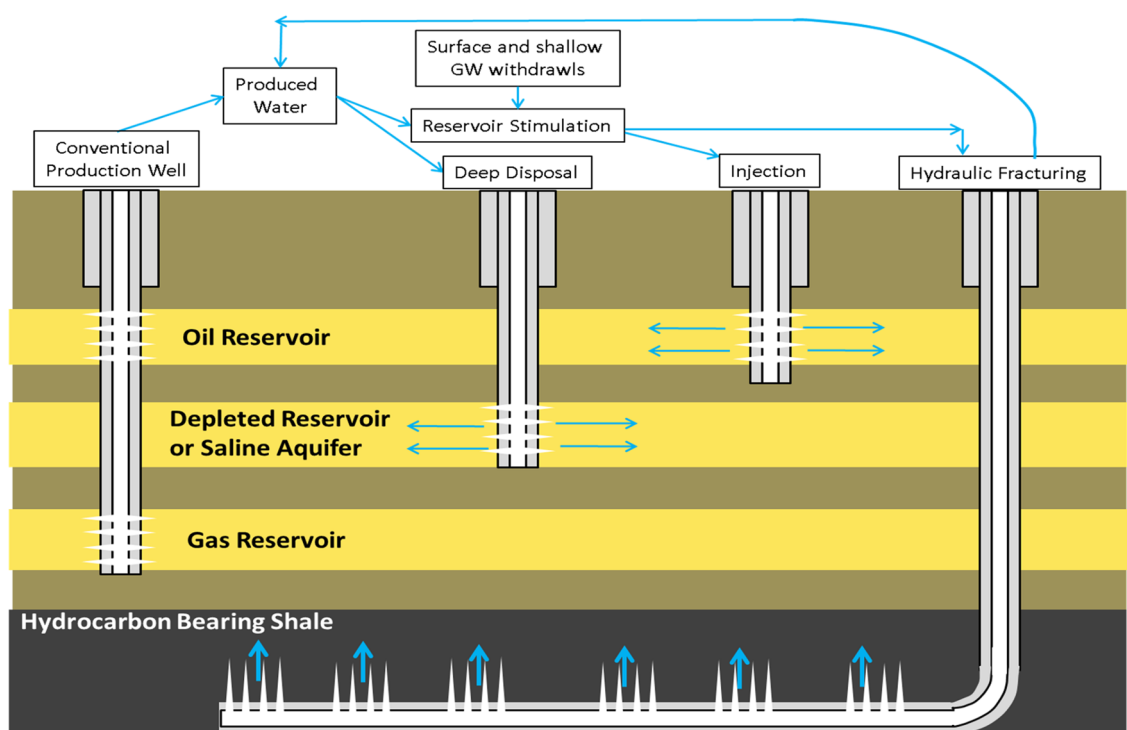


Fig. 1 Conceptual illustration of shale gas production (conventional vs. hydraulic fracturing) and disposition of produced wastewater

depths where the pore water is saline and not suitable for consumption or agricultural purposes. The purpose of deep disposal is for injected fluids to remain in the target formation and not contaminate surrounding sources of water (wastewater confinement). Despite the apparent benefit of trapping unwanted fluids deep underground, some concerns have been raised concerning this practice. First, there is concern that injected wastewater could find a pathway upward into freshwater aquifers along preferential pathways such as faults or leaky wellbores (Akob et al. 2016; Carr-Wilson 2014; Ferguson 2015; US EPA 2014; Chesnaux et al. 2013). Second, deep injection has been increasingly linked to induced earthquakes, including some events of magnitude 4 and greater (McGarr 2014; Atkinson et al. 2016; US EPA 2015; Goebel et al. 2016; Schultz et al. 2014; Wisen et al. 2019b).

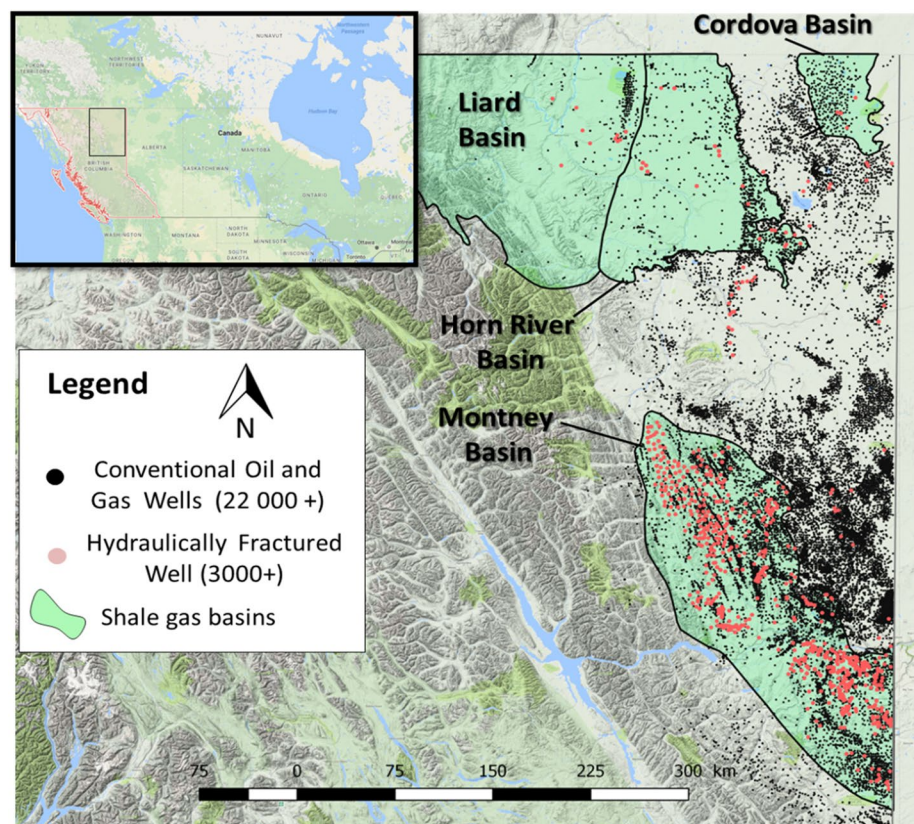
Thanks to hydraulic fracturing, Northeastern British Columbia (NEBC) now has access to one of the world's largest reserves of recoverable shale gas (US EIA 2015), contained in the Montney and Horn River Basins (Fig. 2).

In BC, deep disposal is the only permitted method for disposing of wastewater that is not re-used for subsequent reservoir stimulation operations, according to the British Columbia Oil and Gas Commission (BC OGC 2018). Deep disposal in BC is permitted in either depleted reservoirs or deep saline aquifers (BC OGC 2018).

This study examines the current and projected volumes of freshwater consumption and wastewater disposal needed to accommodate continued hydraulic fracturing in NEBC. Although the BC OGC has provided geological estimates of recoverable gas volumes, there is no estimate of total water footprint. Hughes (2015) estimated how many wells need to be drilled in NEBC in order to produce the remaining gas reserves. However, Hughes (2015) did not calculate how much freshwater will be withdrawn, how much wastewater will be produced and how much wastewater will require deep disposal, for all these wells.

No study has yet attempted to estimate the volumes of wastewater that will be generated from hydraulic fracturing activities and how much water will require deep disposal after part of the produced wastewater can be reused for hydrofracking. The two issues of 1—freshwater withdrawal applying a stress on freshwater quantity and 2—deep disposal of wastewater implying a risk of cross-contamination of freshwater (quality) are investigated in this study. To achieve this end, the presented study aims at developing a methodology for estimating, on the one hand, the future quantities of freshwater that will be needed for hydrofracking, and on the other hand, the future quantities of wastewater produced by hydrofracking in shale gas formations. These estimates ultimately make it possible to determine the quantity of water that will need to be re-injected into

Fig. 2 Distribution of shale gas and conventional wells in NEBC. Not all wells displayed are currently active producers



the exploited shale gas formations, according to different scenarios of re-use of wastewater for hydrofracking.

In some cases, well operators re-use a portion of generated wastewater for subsequent hydraulic fracturing operations, which has the combined effect of reducing both freshwater consumption and the need for deep disposal. This study, therefore, considers three scenarios in order to estimate anticipated volumes of freshwater withdrawal and deep waste disposal. This includes one scenario in which all future hydraulic fracturing fluids are sourced from wastewater and a second in which all fluids are sourced from freshwater withdrawals. Last, in the third scenario, the current rate of wastewater re-use is calculated and applied to all future production.

The study is illustrated with the specific case of the unconventional gas exploitation occurring in NEBC for which a large database from the BC OGC is available regarding two specific basins: the Montney and the Horn River basins. The database contains the relevant information of water use and production of the past and current shale gas production wells. Based on this information, the database will allow the prediction of the future water footprint of the exploitation of the two shale basins under study using the developed methodology. This methodology could then be used for any other unconventional shale gas formations exploited worldwide in order to characterize the future water footprint of gas exploitation.

Hydrostratigraphy of NEBC and studied units

Hydrostratigraphy

NEBC is located in the northwestern-most corner of the Western Canadian Sedimentary Basin (WCSB). At its deepest, the WCSB extends 3 km below the surface in NEBC and contains 15 hydrostratigraphic units classified as deep saline aquifers (Fig. 3). With the exception of the two uppermost units, the Dunvegan and the Cardium, all these saline aquifers are major producers of conventional gas (more than 100,000 m³ of cumulative production) or gas with lesser amounts of oil. These gas-bearing saline aquifers are separated by ten aquitards and the Charlie Lake aquiclude. The Charlie Lake aquiclude is a predominantly evaporite sequence that contains isolated detrital sequences containing oil and gas accumulations. Two of the ten aquitards are the gas-bearing Montney and Horn River, exploited through the unconventional technique of hydraulic fracturing. These two shale units do not extend laterally over the entire province; the Montney is concentrated in the south and the Horn River in the north (Fig. 2). The Horn River aquitard is divided geologically and geographically into two basins: the Horn

River Basin and Cordova Embayment, and the Liard Basin. The Liard basin is the stratigraphic equivalent of the Horn River and Cordova basins; however, it is offset from the latter by the Bovie Fault. There is little to no gas production from the other aquitards.

Studied units

As previously described, the main shale gas units are the Montney and Horn River aquitards. For the purposes of well performance and water impact analysis, these units are further subdivided as presented in Table 1. These subdivisions are based on those proposed by the British Columbia Oil and Gas Commission (BC OGC 2015) in their most recent document on shale gas reserves. In each of these study units, the BC OGC has calculated an estimated recoverable volume of gas based on geostatistical analysis (Table 1).

As the Montney aquitard has been more extensively developed than the Horn River aquitard, it has been subdivided into both geographic and geological zones, including the upper Montney A and the lower Montney B. Due to limited production data, the Liard basin was not analysed in this study.

For each study unit, the goal of the present study was to calculate ultimate freshwater consumption as well as ultimate wastewater production for fracking. In other words, if the estimated volumes of recoverable gas in place are exploited, how much freshwater resources will be consumed and how much wastewater will be generated? Any leftover wastewater not re-used in hydraulic fracturing operations in BC requires permanent disposal via deep disposal wells.

Methodology

The methodology developed to assess the future global water footprint in NEBC is composed of the following steps:

1. Estimating the volumes of freshwater and/or wastewater that are needed for future hydrofracking based on the volumes of water that have been used in the past for hydrofracking the current active and past deactivated wells in the Horn River and Montney basins. Knowledge of the quantity of water that has been required to extract a certain quantity of gas makes it possible to anticipate the future needs of water as a function of the future quantities of gas to be extracted by hydrofracking.
2. Estimating the volumes of wastewater resulting from the future exploitation of unconventional gas in the two basins. These future required volumes of freshwater are estimated using a wastewater-to-gas ratio (volume of wastewater divided by the volume of extracted gas) value that is calculated for each basin from the data

Fig. 3 Hydrostratigraphy of NE British Columbia (adapted from Bachu 2002)

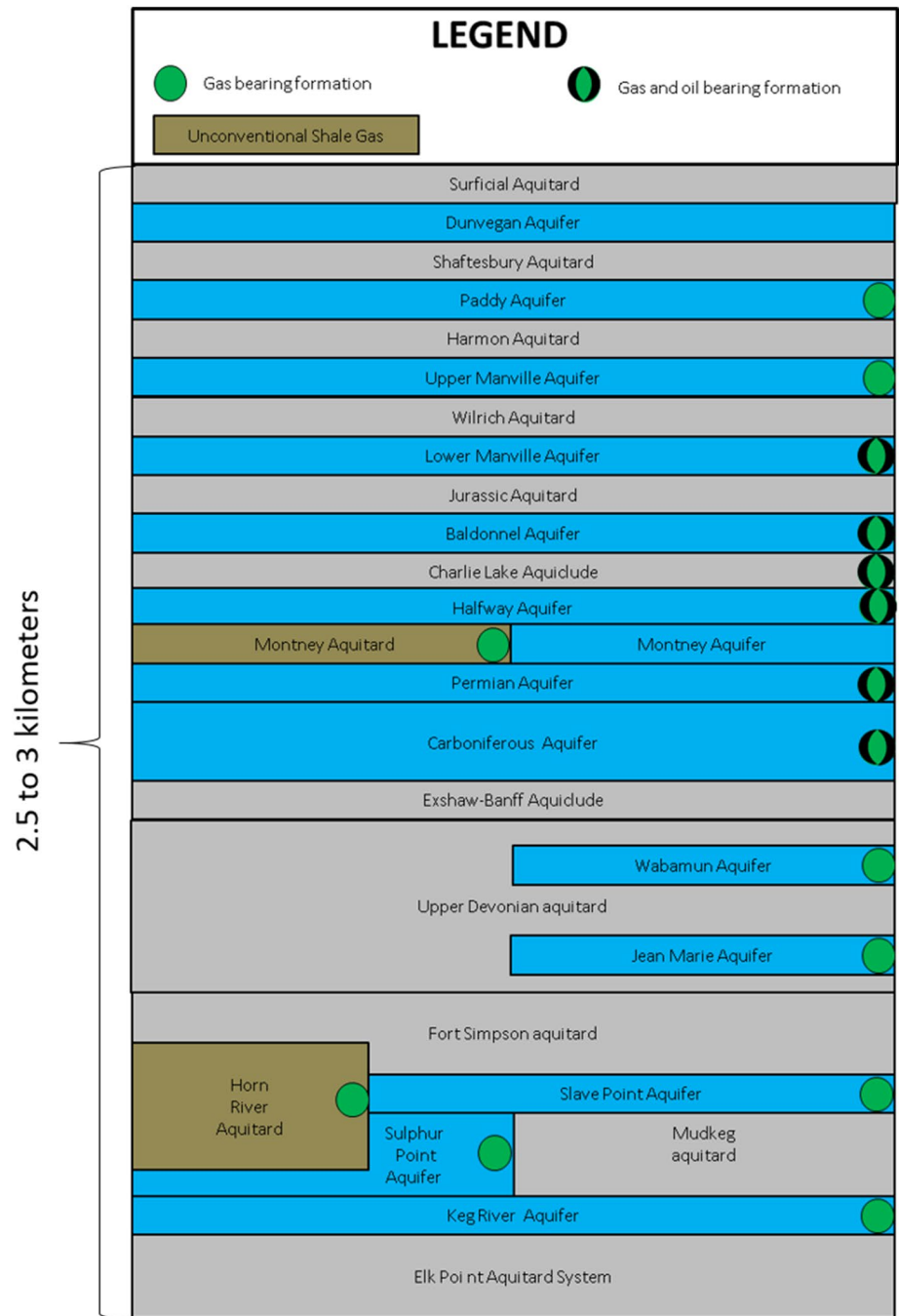


Table 1 Study units and gas resources

Study unit	Shale unit	Sub-unit	Geographic area	Billion cubic metres (B m ³) of recoverable gas	Recoverable gas in trillion cubic feet (BCO GC 2015)
Montney A—South (heritage)	Montney	A	Montney South (Heritage)	4084	144
Montney A—North			Montney North	3209	113
Montney B—North		B		351	12
Horn River—Horn River	Horn River		Horn River Basin	2209	78
Horn River—Cordova Embayment			Cordova Embayment	225	9

available in the database. It is indeed assumed that each basin has its own wastewater-to-gas ratio value which characterizes the specific behaviour of each basin.

3. Applying different scenarios of wastewater reuse for fracking in order to calculate the volume of wastewater to be disposed and also to calculate the volume of freshwater that will be needed for the future shale gas extraction. This will make it possible to assess the global water footprint of the future extraction of shale gas until the complete depletion of the known reserves.
4. Determining and comparing the average total dissolved solids (TDS values) of wastewater produced by conventional and unconventional gas exploitation. This study allows an assessment of the qualitative aspects of shale gas activities regarding the quality of wastewater.

All data on reservoir production and injection volumes as well as on the chemistry of wastewater produced from the Montney and Horn River were extracted from the Integrated Resource Information System (IRIS), which is maintained and updated, by the British Columbia Oil and Gas Commission on a monthly basis. This data is available to download for free from the BC OGC website. Production decline curves were generated for each geological unit by normalizing and averaging time in terms of production months for each producing well from a given unit. Data from approximately 3500 and 250 wells in the Montney and Horn River, respectively, have been extracted from the database and processed in the framework of the present study.

Results

Volumes of gas and wastewater produced by conventional and unconventional gas exploitation in the entire province of BC

Figure 4 presents the annual production of conventional and unconventional gas in British Columbia. This figure considers all of the 25,000 gas-producing wells in the province, the majority of which are gas producers.

Figure 4 has been produced using data from the Integrated Resource Information System (IRIS) database provided by the BC OGC (2018).

Since about 2005, conventional gas production has been in decline; however, production from the unconventional Horn River and Montney plays has contributed to a net increase in annual gas production as well as wastewater (Fig. 4).

Hydraulic fracturing data and production decline analysis in the Montney and Horn River basins

As previously stated, data from approximately 3500 and 250 wells located in the Montney and Horn River, respectively, have been treated in the IRIS database of the BC OGC (2018). This section presents the results for the injected volumes of water and for the produced wastewater in the Montney and Horn River Basins. Figure 5 presents the results for the average injected volume of water per well in the Montney, Horn River and Liard basins and Fig. 6 presents the volumes of injected water per well length. Fracked wells drilled in the Horn River and Cordova sub-units to the north inject higher volumes of water than those in the Montney units to the south (Fig. 5). These injected volumes

Fig. 4 Annual production of conventional and unconventional gas in British Columbia. Unconventional shale gas is produced from the Horn River and Montney Units. G is for billions, M for millions, annual gas production volumes for 2016

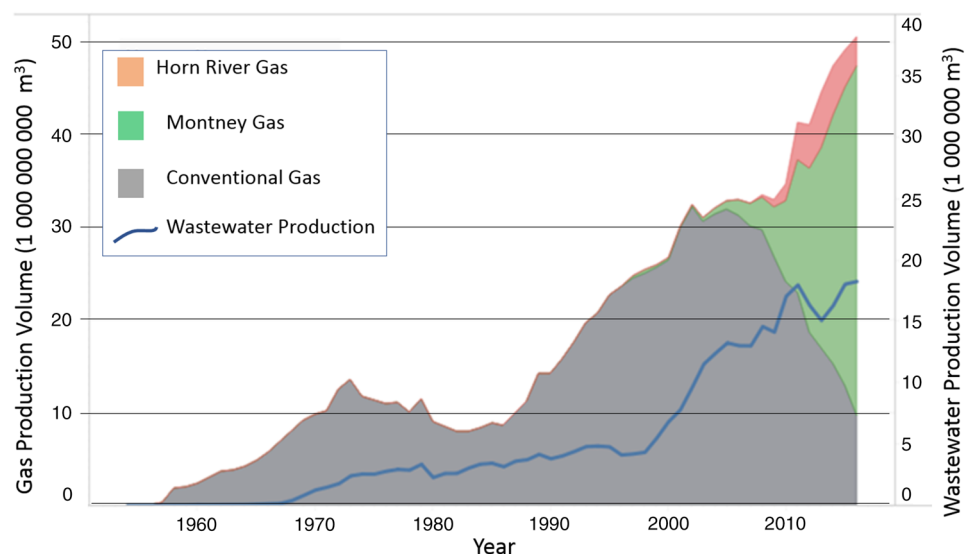


Fig. 5 Average injected volumes per well in each study unit

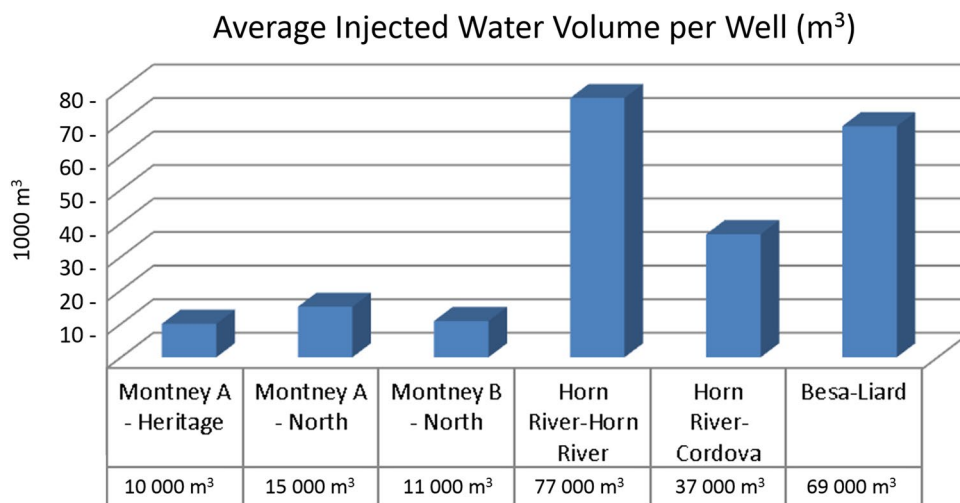
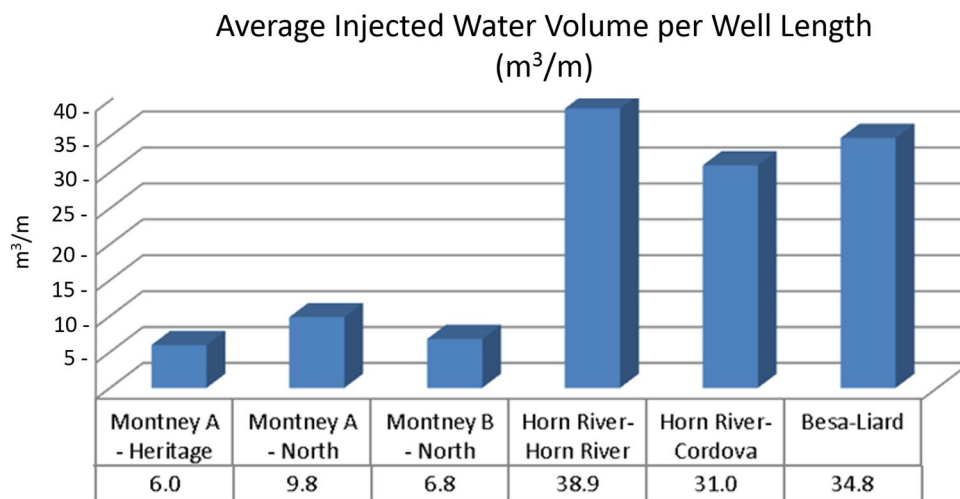


Fig. 6 Average injected water volume for wells in each study unit



are also high in the Liard Basin; however, the average for Liard is based on only three wells and as a result may not be fully representative of future production. In general, wells that are horizontally longer inject higher volumes of water, and wells in the Northern Horn River shale units are on average longer than those in the Montney. Despite this, even when normalizing fracking injection volumes to the horizontal length of the well, a large difference is observed between the Southern Montney and the Northern Horn River units (Fig. 6). The Horn River units consume roughly five times more water than Montney wells for the same horizontal wellbore length. Horn River shales also consume more water per volume of gas produced compared to those in the Montney (Fig. 7).

Water consumption per produced gas volume is highest in the Horn River units located within the Cordova Basin. Despite injecting substantially higher volumes of water during the hydraulic fracturing process, wells in the Cordova basin produce volumes of gas similar to those in the

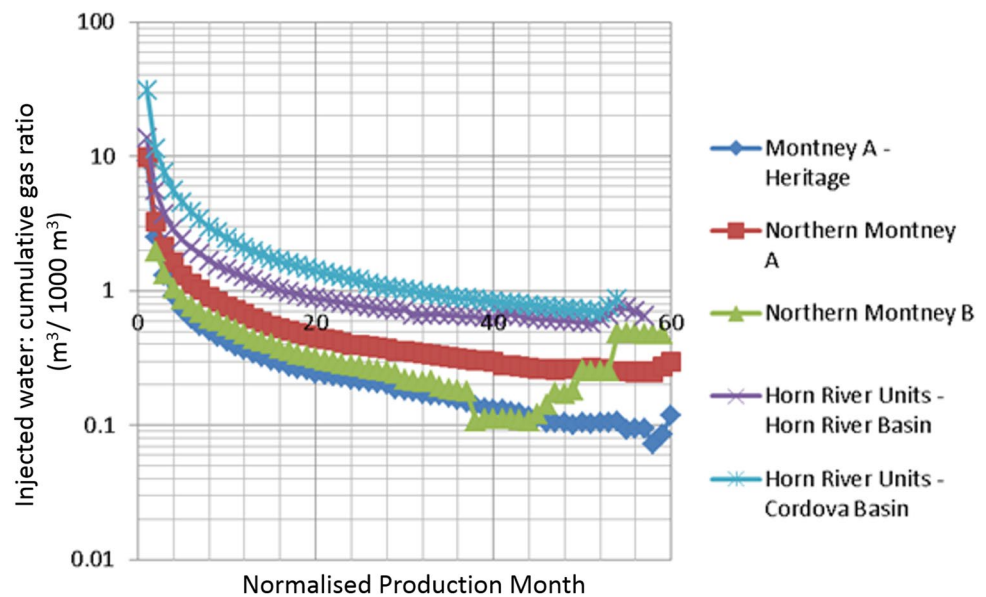
Montney units (Fig. 8a). Wells located within the Horn River basin however, produce substantially higher volumes of gas.

Waste volumes are highest in the Cordova basin, followed by the Horn River basin, and Montney shale wells (Fig. 8b). This is also true when comparing wastewater volumes to gas production (Fig. 9). Ratios of cumulative wastewater to cumulative gas production tend to level out at around 40 months and range between 0.1 and 0.2 m³ of water per 1000 m³ of gas for all zones except the Cordova Basin (Fig. 9).

Projected volumes of consumed freshwater and wastewater by future shale gas production

The ratios of injected water: gas and wastewater: gas presented in Fig. 9 are applied to volumes of gas in place estimated by the BC OGC in order to calculate ultimate volumes of consumed freshwater and produced wastewater by future shale gas production (Table 2).

Fig. 7 Injected water volume during fracking divided by cumulative gas production



In all cases except the Montney A—South, exploitation of shale is projected to inject more water than what will be produced. This is expressed by the net water: produced gas ratio which is defined as (produced wastewater-injected water)/cumulative gas production ($\text{m}^3/1000 \text{m}^3$). Water loss is highest in the Horn River shales of the Horn River basin. Water loss is the lowest in Montney shales of the Montney south field, where projected wastewater production is estimated to approximate freshwater injection needs.

Scenarios of wastewater re-use and corresponding projected volumes of freshwater withdrawal and wastewater requiring deep disposal

Analysis of the FracFocus database and freshwater withdrawal data from the IRIS database suggest that approximately 40% of hydraulic fracturing fluids were sourced from produced wastewater and 60% from freshwater withdrawals. The database, however, does not detail the source of recycled produced wastewater. Therefore, it is unknown what portion, if any, of recycled produced wastewater is sourced from conventional oil and gas wells in the vicinity of fracking operations.

Three scenarios were applied in order to calculate ultimate volumes of freshwater withdrawals and wastewater requiring deep disposal (Table 3). In the framework of these scenarios, the Montney A and B units within the Montney North field are grouped together, given that they occupy the same geographic location.

Even if all wastewater produced from fracking operations were to be re-used (scenario 1), there would still be the requirement to withdraw 1.6 billion cubic metres of water. Alternatively, in the worst-case scenario in which no produced

wastewater is re-used, 3 billion cubic metres of water would need to be withdrawn. Additionally, the worst-case scenario would generate 1.3 billion cubic metres of wastewater requiring deep disposal. In the most likely scenario where 40% of fracking fluids are derived from recycled wastewater, the projected volume of freshwater withdrawals is similar to the best-case scenario at 1.8 billion cubic metres.

Assuming that 40% of injected water were to be sourced from produced wastewater, as suggested in the third scenario, deep disposal could be entirely avoided within the Horn River basin. This is important, as there is much less capacity for deep disposal in that study unit than in the others (absence of depleted permeable formations). Alternatively, this is the geographic zone with the highest demand for freshwater extraction.

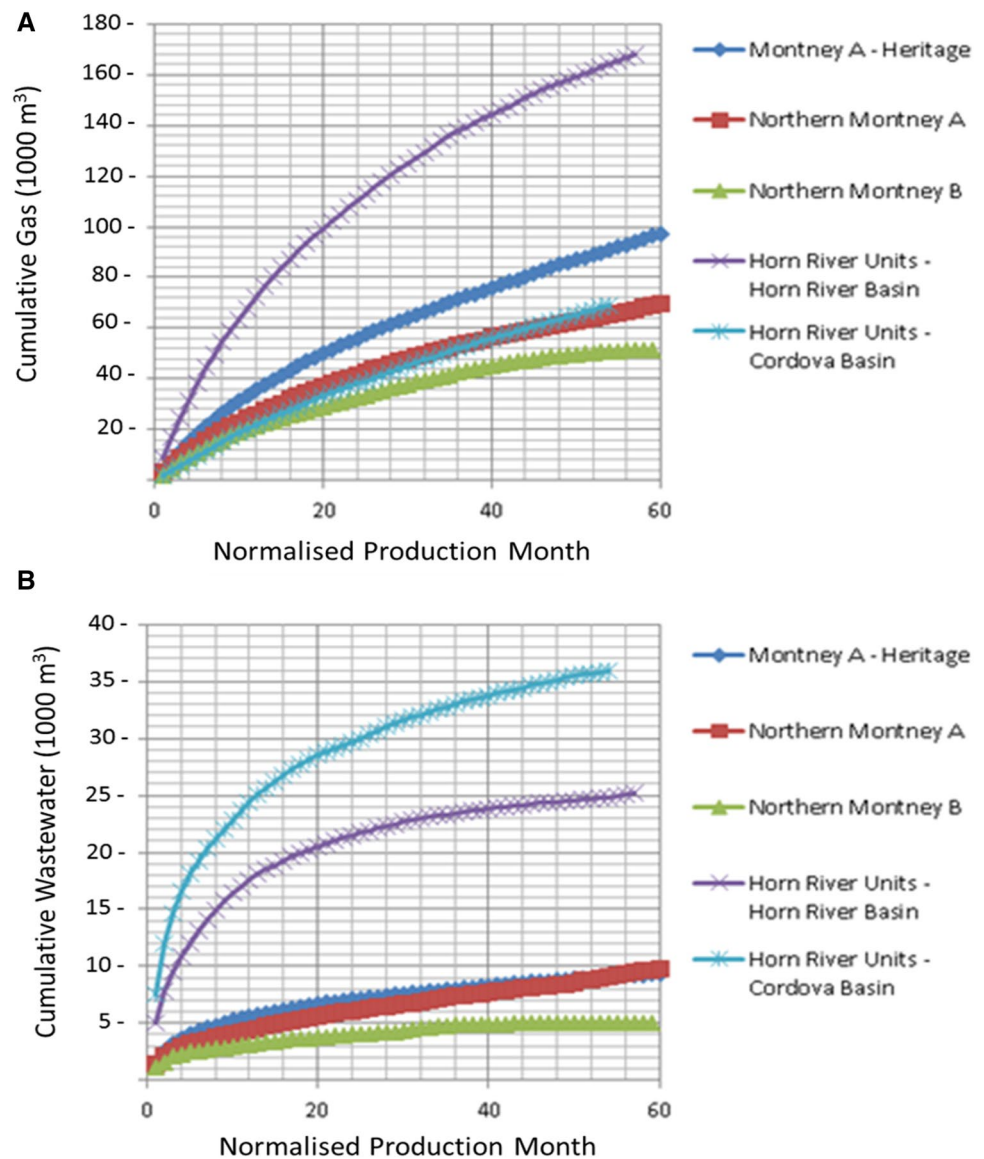
Comparing the quantitative and qualitative aspects of water footprint of conventional and unconventional shale gas production in BC

The quantity of wastewater produced from shale gas is not necessarily larger than that of conventional production in BC (Fig. 10). However, the quality is much lower if total dissolved solids (TDS) is used as the sole criteria (Fig. 10). The average TDS for produced wastewater from the Horn River and Montney units is 100,000 and 162,000 mg/L, respectively.

Discussion

The exploitation of the remaining shale reserves in British Columbia will require between 1.65 and 3 billion cubic metres of freshwater. These figures represent 2–4% of the

Fig. 8 Cumulative gas and wastewater production curves for study units



total annual flux of surface water runoff in Northeastern British Columbia, which is estimated at around 120 billion cubic metres per year (Government of BC 2015). The large-scale impact of freshwater extraction is moderated by the consideration that the remaining reserves of shale gas in the province will be exploited over several decades. The overall impact of freshwater extraction for purposes of hydraulic fracturing appears to be manageable in Northeastern British Columbia. To provide some perspective by means of a comparison, in 2017 the city of Montreal consumed 767 million cubic metres water. It may be posited that the total volume of freshwater required to be extracted for hydraulic fracturing to produce the remaining reserves of shale gas in BC over several decades is roughly equivalent to a volume 2–4 times greater than that consumed by a large Canadian city in a single year.

The proper management of freshwater resources will nevertheless require the investigation of impacts at a local scale, that is to say, the location and rate of specific withdrawal points throughout the year. In British Columbia, this management falls under the responsibility of the BC OGC which grants freshwater withdrawal permits to oil and gas companies based on their evaluation of the potential impact of production over short- and long-term periods. These permits may be revoked in times of low stream flow or drought. In British Columbia, these water withdrawals are also subject to the environmental requirements of the province’s *Water Sustainability Act*.

Concerning the production of wastewater, the results of this study demonstrate that hydraulically fractured wells do not generate more wastewater than conventional oil and gas wells in British Columbia. Nevertheless, the growth of the

Fig. 9 Ratio of cumulative wastewater to cumulative gas production

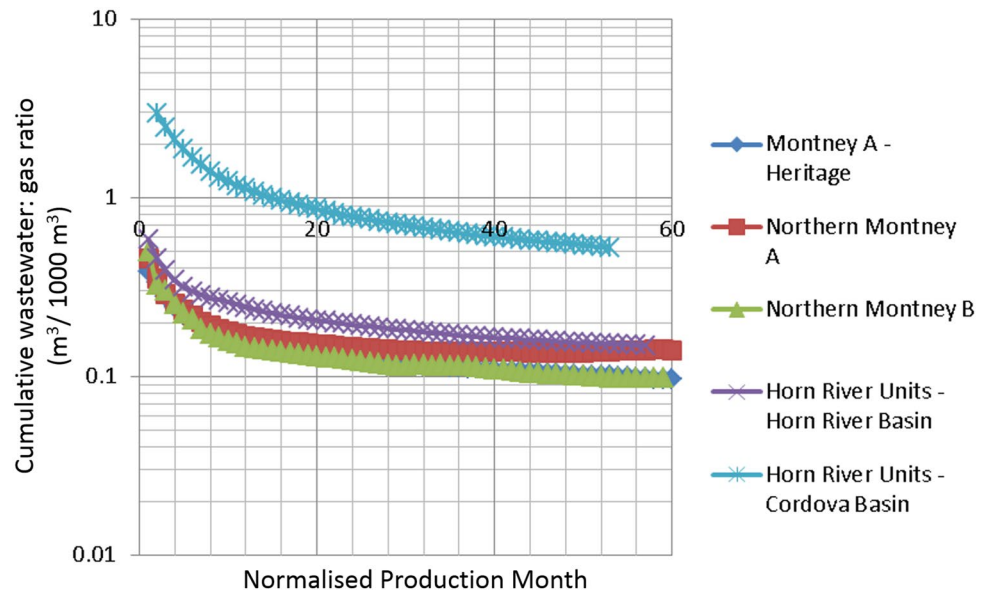


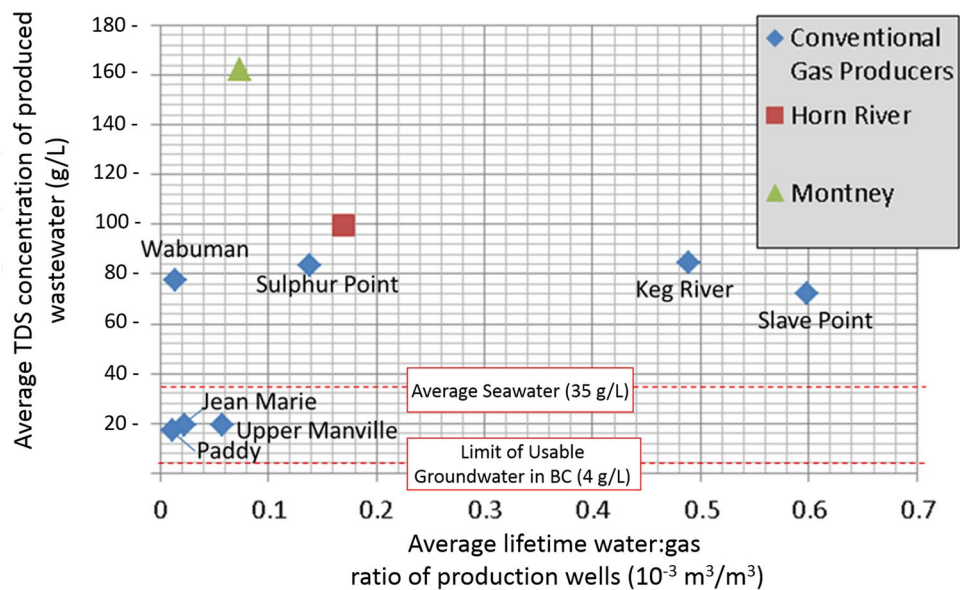
Table 2 Projected volumes of consumed freshwater and produced wastewater from hydraulic fracturing in each study unit

Geographic area	Study unit	Billion cubic metres (Bm ³) of recoverable gas	Injected freshwater:gas ratio (m ³ /1000 m ³)	Produced wastewater:gas ratio (m ³ /1000 m ³)	Net water:gas ratio (m ³ /1000 m ³)	Injected fresh-water volume (million m ³)	Produced wastewater volume (million m ³)
Montney South (heritage)	Montney A—South (heritage)	4084	0.10	0.10	0	408	408
Montney North	Montney A—North	3209	0.25	0.14	-0.11	802	449
	Montney B—North	351	0.20	0.10	-0.10	70	35
Horn River Basin	Horn River—Horn River	2209	0.70	0.15	-0.55	1546	331
Cordova Embayment	Horn River—Cordova Embayment	255	0.70	0.50	-0.20	178	127

Table 3 Scenarios of wastewater re-use and corresponding projected volumes of freshwater withdrawal and wastewater requiring deep disposal

Study unit	Scenario 1: all wastewater re-used		Scenario 2: no wastewater re-used		Scenario 3: 40% of fracking fluids sourced from recycled wastewater	
	Freshwater withdrawal volume (million m ³)	Wastewater disposal volume (million m ³)	Freshwater withdrawal volume (million m ³)	Wastewater disposal volume (million m ³)	Freshwater withdrawal volume (million m ³)	Wastewater disposal volume (million m ³)
Montney South (heritage)	0	0	408	408	245	245
Montney North A and Montney North B	388	0	872	484	523	135
Horn River Basin	1215	0	1546	331	928	0
Cordova Embayment	51	0	178	127	107	56
Total	1654	0	3005	1351	1803	436

Fig. 10 Average salinity of produced wastewater vs. average water to gas ratio



shale gas industry in the province will consequently increase the volume of wastewater generated, which will require either permanent disposal or re-use in subsequent hydraulic fracturing operations. Currently, the best option for the permanent disposal of these wastewater is deep injection into permeable saline formations containing groundwater unfit for human consumption. However, the increase in reservoir pressure generated by deep disposal wells injecting wastewater has been known to trigger seismicity throughout Canada and the United States (Rubinstein and Mahani 2015). The increase in hydraulic head of the disposal formation also increases the possibility of ascending cross-contamination if a hydraulic connection was to exist or be created between the surface and the disposal formation (Wisen et al. 2019).

The re-use of wastewater in subsequent hydraulic fracturing operations should greatly contribute to attenuating the necessity of deep disposal, and, at the same time, to reducing the volume of freshwater consumed by the process. Indeed, the results of this study show that in Northeastern British Columbia, the volumes of wastewater produced by shale gas wells are lesser than those required for injection as hydraulic fracturing fluid.

Finally, it must be underlined that very few studies in other parts of the world have addressed the issue of water footprint in terms of quantifying the volumes of freshwater that are needed for hydrofracking and in terms of volumes of wastewater resulting from the exploitation and future exploitation of unconventional gas. This makes it difficult to conduct a comparison of the results of our study against those of other studies, with the intent to provide a critical analysis on our research results. For example, Warner et al. (2013) as well as Olmstead et al. (2013) have addressed the issue of the impacts of shale gas wastewater disposal on the surface water quality in Pennsylvania. These two studies have shown

increased concentrations of chloride and bromide and high levels of contaminants in the surface waters surrounding the region of the Marcellus shale gas basin. They reported TDS concentrations of shale gas waste waters comprised between 0.8 and 300 g/L, which results agree with the TDS concentrations observed in our study (Fig. 10), namely, between 100 and 160 g/L for the Horn, and Montney basins, respectively. According to the same authors, the overall estimated volume of oil and gas wastewater has increased during recent years to reach values between 3.1 and 3.8 million m^3/year . Concerning the reuse of waste water, Warner et al. (2013) as well as Olmstead et al. (2013) reported that an estimated 70% of the flowback and produced fluids is reused. This ratio of 70% is much higher than the ratio of reused water observed and documented in BC (40%); therefore, the ratio of water reuse could potentially be improved in BC. Another study by Vandecasteele et al. (2015) has investigated the impact of shale gas development on water resources consumption in Northern Poland. This study is not based on observed field results, but rather on modelling scenarios of future shale gas exploitation. It estimated that water use per shale gas well would be between 8000 and 19,000 m^3 , which is lower than the values that are observed in BC (see Fig. 5); these range between 10,000 and 77,000 m^3 per well.

Conclusions

Using data from the British Columbia Oil and Gas Commission (data from approximately 3750 wells), the present study examines the volumes of freshwater injected and the volumes of wastewater produced in the context of hydraulically fractured gas wells in Northeastern British Columbia, Canada. A methodology was developed for analysing the

existing data and also for producing preliminary estimates of the future quantities of freshwater that will be needed for hydrofracking in BC, as well as the future quantities of wastewater that will be produced by hydrofracking in shale gas formations in BC. In addition, this study also proposed tentative estimates of the quantity (volume) of freshwater that would potentially be needed in different scenarios of re-use of wastewater for hydrofracking (for the re-injection and re-use of various ratios of fresh and/or waste water into the shale gas formations to be exploited). The developed methodology could be used to assess the water footprint of hydraulic fracturing in formations located in other geographical locations around the world.

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