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 3 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 meters, 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.

1. 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 9 gas-bearing shale formations are spread out over 5 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., 2019) 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.
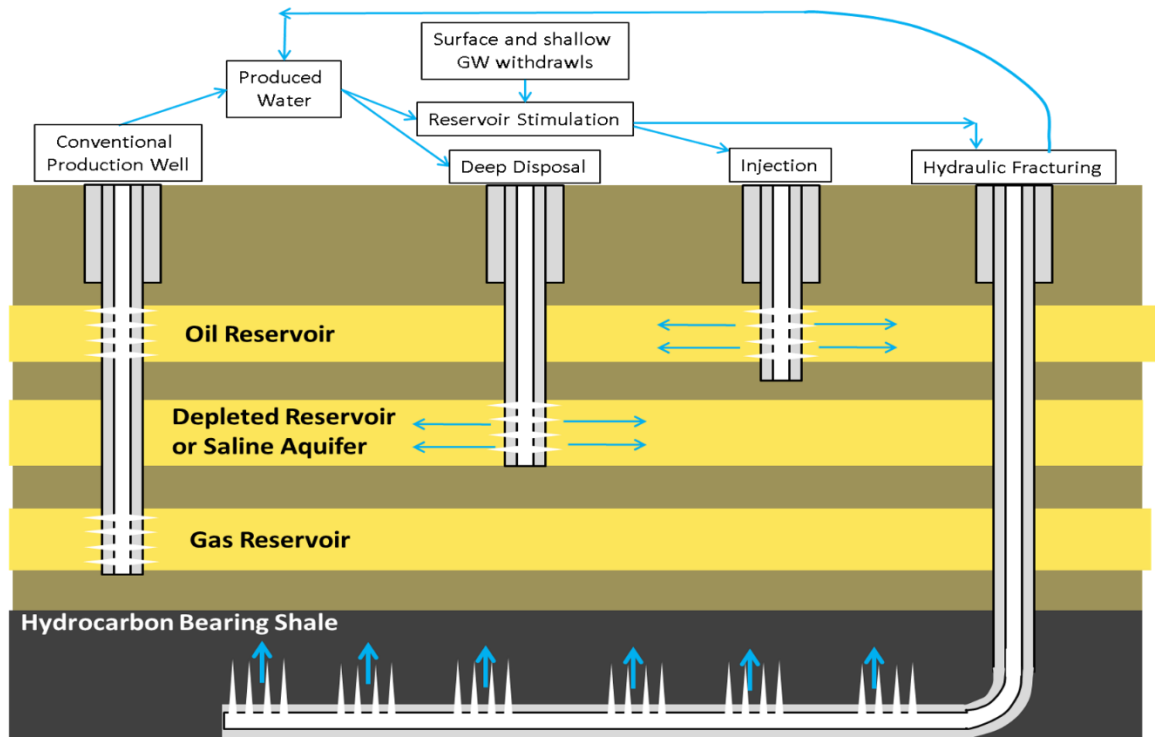
Figure 1: Conceptual illustration of shale gas production (conventional vs. hydraulic fracturing) and disposition of produced wastewater.

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 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 kilometer. 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

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92 water) along with formation brines (produced water) during production of the well (Vengosh et al., 2014;
93 Lutz et al., 2013). Produced water from shale gas is characterized by high concentrations of toxic elements
94 such as barium, strontium and radioactive radium. Additionally, as with most conventional reservoirs,
95 produced water is highly saline and often contains dissolved organic compounds (Vengosh et al., 2014).
96 These toxic and radioactive elements typically show a direct correlation with salinity (Vengosh et al., 2014).
97 Flowback and produced water are sometimes collectively termed flowback-produced (FP) water (Scanlon et
98 al., 2016) or more generally, fracking "wastewater" (Lutz et al., 2013). Typically, the salinity of fracking
99 wastewater increases over time as the chemistry shifts from flowback to brine-dominated (Vengosh et al.,
100 2014).

101

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

112

113 Deep disposal is the process by which wastewater is injected through a disposal well into deep saline
114 aquifers. Deep saline aquifers are permeable formations located at depths where the pore water is saline and
115 not suitable for consumption or agricultural purposes. The purpose of deep disposal is for injected fluids to
116 remain in the target formation and not contaminate surrounding sources of water (wastewater confinement).
117 Despite the apparent benefit of trapping unwanted fluids deep underground, some concerns have been raised
118 concerning this practice. Firstly, there is concern that injected wastewater could find a pathway upward into
119 freshwater aquifers along preferential pathways such as faults or leaky wellbores (Akob et al., 2016; Carr-
120 Wilson, 2014; Ferguson, 2015; US EPA, 2014; Chesnaux et al., 2013). Secondly, deep injection has been
121 increasingly linked to induced earthquakes, including some events of magnitude 4 and greater (McGarr,
122 2014; Atkinson et al., 2016; US EPA, 2015; Goebel et al., 2016; Shultz et al., 2014).

123

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

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

131

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

138

139 No study has yet attempted to estimate the volumes of wastewater that will be generated from hydraulic
140 fracturing activities and how much water will require deep disposal after part of the produced wastewater can
141 be reused for hydrofracking. The two issues of 1-freshwater withdrawal applying a stress on freshwater
142 quantity and 2-deep disposal of wastewater implying a risk of cross-contamination of freshwater (quality)
143 are investigated in this study. To achieve this end, the presented study aims at developing a methodology for

144   estimating, on the one hand, the future quantities of freshwater that will be needed for hydrofracking, and on
145   the other hand, the future quantities of wastewater produced by hydrofracking in shale gas formations. These
146   estimates ultimately make it possible to determine the quantity of water that will need to be re-injected into
147   the exploited shale gas formations, according to different scenarios of re-use of wastewater for hydrofracking.
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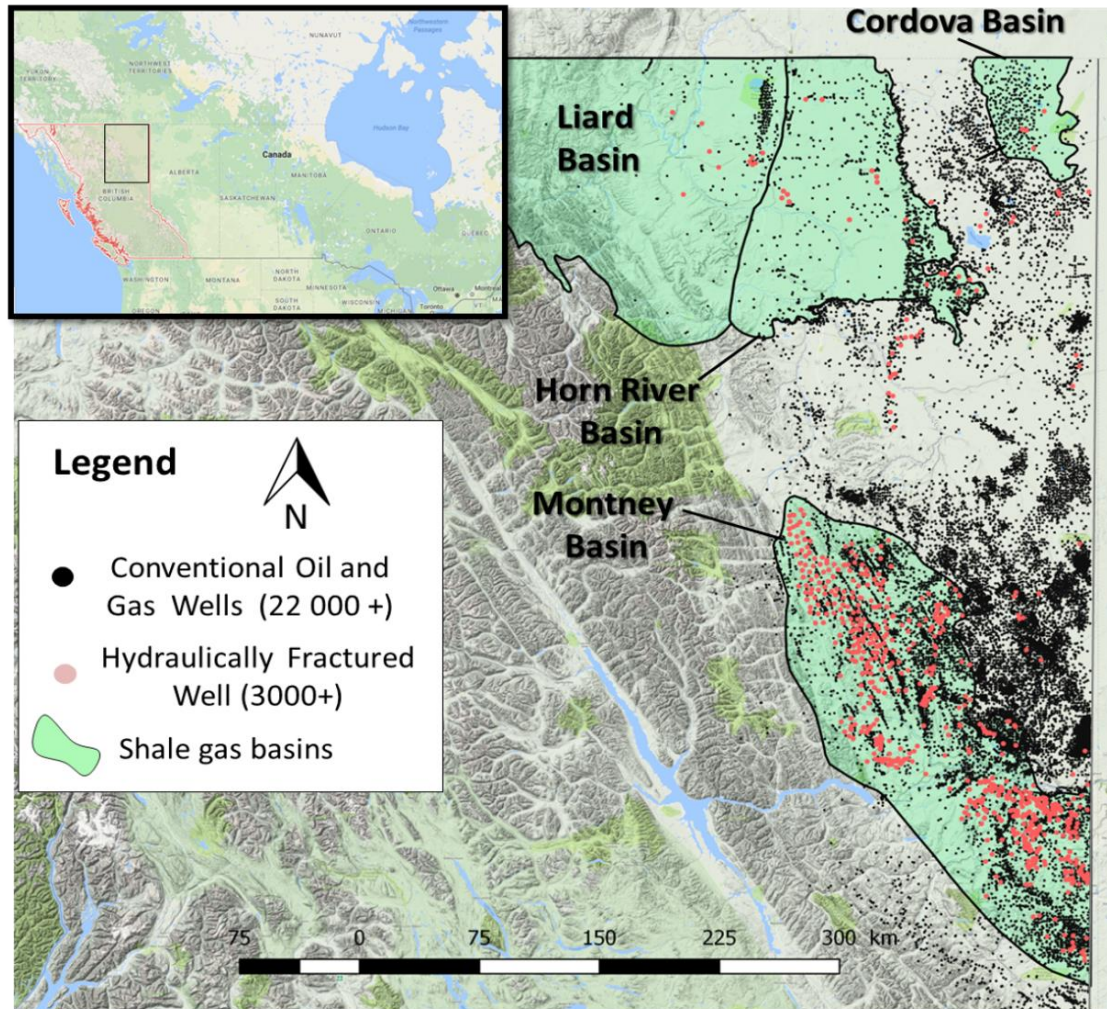
149

150   Figure 2: Distribution of shale gas and conventional wells in NEBC. Not all wells displayed are currently
151   active producers.

152
153   In some cases, well operators re-use a portion of generated wastewater for subsequent hydraulic
154   fracking operations, which has the combined effect of reducing both freshwater consumption and the need
155   for deep disposal. This study therefore considers three scenarios in order to estimate anticipated volumes of
156   freshwater withdrawal and deep waste disposal. This includes one scenario in which all future hydraulic
157   fracturing fluids are sourced from wastewater and a second in which all fluids are sourced from freshwater
158   withdrawals. Lastly, in the third scenario, the current rate of wastewater re-use is calculated and applied to
159   all future production.

160   The study is illustrated with the specific case of the unconventional gas exploitation occurring in
161   NEBC for which a large database from the BC OGC is available regarding two specific basins: the Montney

162 and the Horn River basins. The database contains the relevant information of water use and production of the
163 past and current shale gas production wells. Based on this information, the database will allow the prediction
164 of the future water footprint of the exploitation of the two shale basins under study using the developed
165 methodology. This methodology could then be used for any other unconventional shale gas formations
166 exploited worldwide in order to characterize the future water footprint of gas exploitation.
167

2 HYDROSTRATIGRAPHY OF NEBC AND STUDIED UNITS

2.1 Hydrostratigraphy

170 NEBC is located in the northwestern-most corner of the Western Canadian Sedimentary Basin
171 (WCSB). At its deepest, the WCSB extends 3 km below the surface in NEBC and contains 15
172 hydrostratigraphic units classified as deep saline aquifers (Figure 3). With the exception of the two uppermost
173 units, the Dunvegan and the Cardium, all these saline aquifers are major producers of conventional gas (more
174 than 100,000 m^3 of cumulative production) or gas with lesser amounts of oil (IRIS 2018). These gas-bearing
175 saline aquifers are separated by 10 aquitards and the Charlie Lake aquiclude. The Charlie Lake aquiclude is
176 a predominantly evaporite sequence that contains isolated detrital sequences containing oil and gas
177 accumulations. Two of the 10 aquitards are the gas-bearing Montney and Horn River, exploited through the
178 unconventional technique of hydraulic fracturing. These two shale units do not extend laterally over the entire
179 province; the Montney is concentrated in the south and the Horn River in the north (Figure 2). The Horn
180 River aquitard is divided geologically and geographically into 2 basins: the Horn River Basin and Cordova
181 Embayment, and the Liard Basin. The Liard basin is the stratigraphic equivalent of the Horn River and
182 Cordova basins; however, it is offset from the latter by the Bovie Fault. There is little to no gas production
183 from the other aquitards (IRIS 2018, 2018).

184

2.2 Studied units

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

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

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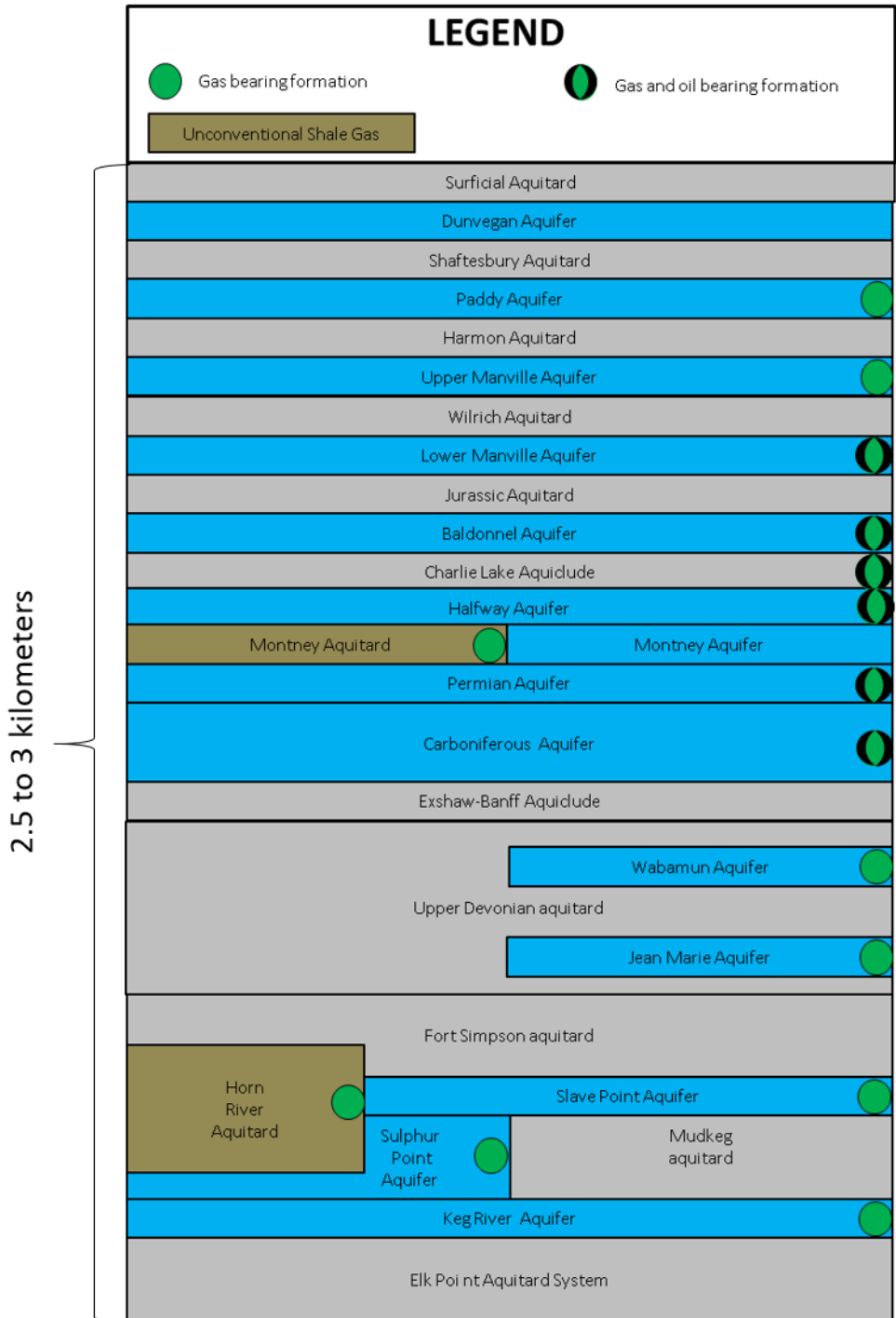198 permanent disposal via deep disposal wells.

199

Figure 3: Hydrostratigraphy of NE British Columbia. Adapted from Bachu (2002).

205 Table 1: Study units and gas resources

Study Unit	Shale Unit	Sub-Unit	Geographic Area	Billion Cubic Meters (B m^3) of Recoverable Gas	Recoverable Gas in Trillion Cubic Feet (BC OGC 2015)
Montney A – South (Heritage)	Montney	A	Montney South (Heritage)	4,084	144
Montney A -North			Montney North	3,209	113
Montney B - North		B		351	12
Horn River – Horn River	Horn River		Horn River Basin	2,209	78
Horn River – Cordova Embayment			Cordova Embayment	225	9

206

3   METHODOLOGY

208 The methodology developed to assess the future global water footprint in NEBC is composed of the following
209 steps:
210

211 1- Estimating the volumes of freshwater and/or wastewater that are needed for future hydrofracking based
212   on the volumes of water that have been used in the past for hydrofracking the current active and past
213   deactivated wells in the Horn River and Montney basins. Knowledge of the quantity of water that has
214   been required to extract a certain quantity of gas makes it possible to anticipate the future needs of water
215   as a function of the future quantities of gas to be extracted by hydrofracking.
216 2- Estimating the volumes of wastewater resulting from the future exploitation of unconventional gas in the
217   two basins. These future required volumes of freshwater are estimated using a wastewater-to-gas ratio
218   (volume of wastewater divided by the volume of extracted gas) value that is calculated for each basin
219   from the data available in the database. It is indeed assumed that each basin has its own wastewater-to-
220   gas ratio value which characterizes the specific behaviour of each basin.
221 3- Applying different scenarios of wastewater reuse for fracking in order to calculate the volume of
222   wastewater to be disposed and also to calculate the volume of freshwater that will be needed for the future
223   shale gas extraction. This will make it possible to assess the global water footprint of the future extraction
224   of shale gas until the complete depletion of the known reserves.
225 4- Determining and comparing the average total dissolved solids (TDS values) of wastewater produced by
226   conventional and unconventional gas exploitation. This study allows an assessment of the qualitative
227   aspects of shale gas activities regarding the quality of wastewater.
228

229 All data on reservoir production and injection volumes as well as on the chemistry of wastewater produced
230 from the Montney and Horn River were extracted from the Integrated Resource Information System (IRIS),
231 which is maintained and updated, by the British Columbia Oil and Gas Commission on a monthly basis. This
232 data is available to download for free from the BC OGC website. Production decline curves were generated
233 for each geological unit by normalizing and averaging time in terms of production months for each producing
234 well from a given unit. Data from approximately 3,500 and 250 wells in the Montney and Horn River,
235 respectively, have been extracted from the database and processed in the framework of the present study.

236

237 # 4 RESULTS

238

239 ## 4.1 Volumes of gas and wastewater produced by conventional and
240 unconventional gas exploitation in the entire province of BC

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

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

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

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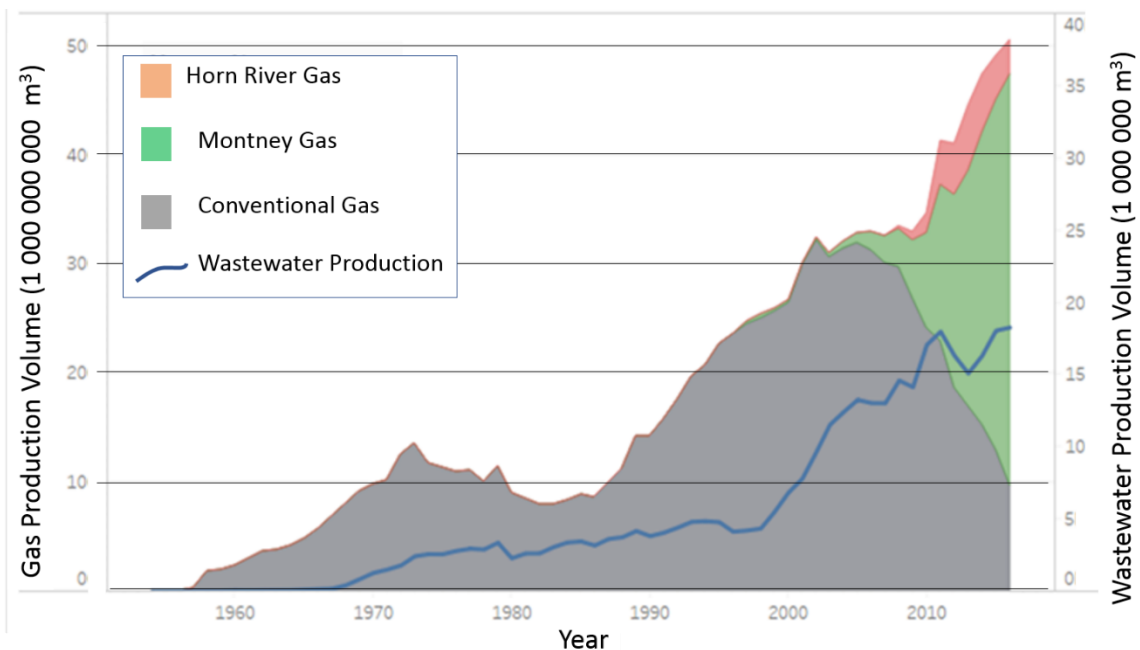
250
251 Figure 4: Annual production of conventional and unconventional gas in British Columbia. Unconventional
252 shale gas is produced from the Horn River and Montney Units. G is for billions, M for millions, annual gas
253 production volumes for 2016.
254

255 ## 4.2 Hydraulic fracturing data and production decline analysis in the Montney
256 and Horn River basins

257 As previously stated, data from approximately 3,500 and 250 wells located in the Montney and Horn River,
258 respectively, have been treated in the IRIS database of the BC OGC (2018). This section presents the results
259 for the injected volumes of water and for the produced wastewater in the Montney and Horn River Basins.
260 Figure 5 presents the results for the average injected volume of water per well in the Montney, Horn River

261 and Liard basins and Figure 6 presents the volumes of injected water per well length. Fracked wells drilled
262 in the Horn River and Cordova sub-units to the north inject higher volumes of water than those in the Montney
263 units to the south (Figure 5). These injected volumes are also high in the Liard Basin; however, the average
264 for Liard is based on only 3 wells and as a result may not be fully representative of future production. In
265 general, wells that are horizontally longer inject higher volumes of water, and wells in the northern Horn
266 River shale units are on average longer than those in the Montney. Despite this, even when normalizing
267 fracking injection volumes to the horizontal length of the well, a large difference is observed between the
268 southern Montney and the northern Horn River units (Figure 6). The Horn River units consume roughly 5
269 times more water than Montney wells for the same horizontal wellbore length. Horn River shales also
270 consume more water per volume of gas produced compared to those in the Montney (Figure 7).

271   Water consumption per produced gas volume is highest in the Horn River units located within the
272 Cordova Basin. Despite injecting substantially higher volumes of water during the hydraulic fracturing
273 process, wells in the Cordova basin produce volumes of gas similar to those in the Montney units (Figure
274 8a). Wells located within the Horn River basin however, produce substantially higher volumes of gas.

275   Wastewastewater volumes are highest in the Cordova basin, followed by the Horn River basin, and
276 Montney shale wells (Figure 8b). This is also true when comparing wastewater volumes to gas production
277 (Figure 9). Ratios of cumulative wastewater to cumulative gas production tend to level out at around 40
278 months and range between 0.1 and 0.2 m^3 of water per 1,000 m^3 of gas for all zones except the Cordova
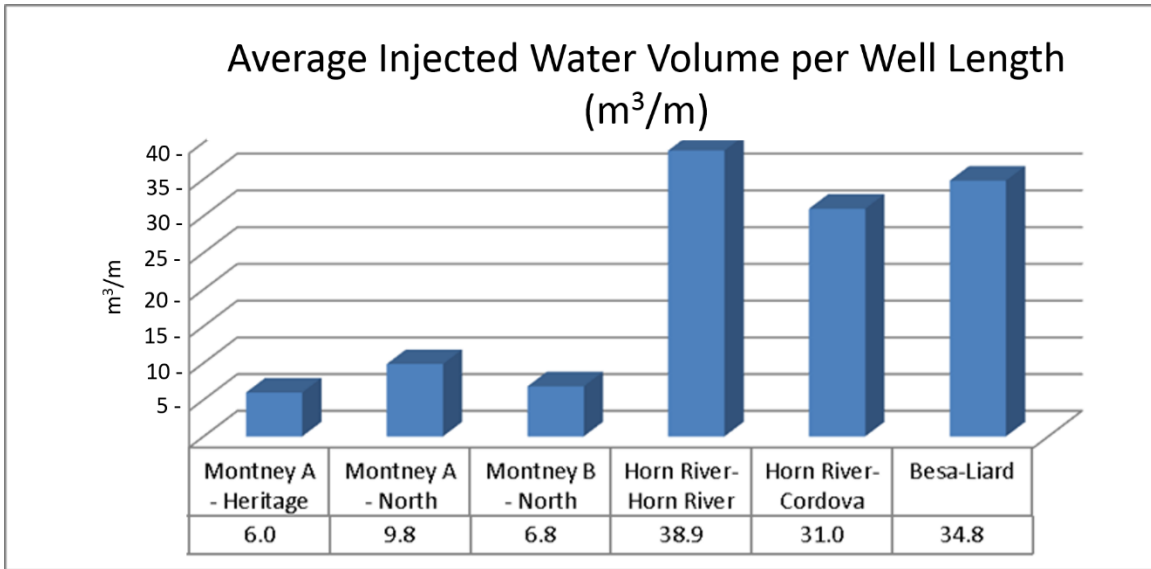279 Basin (Figure 9).

280
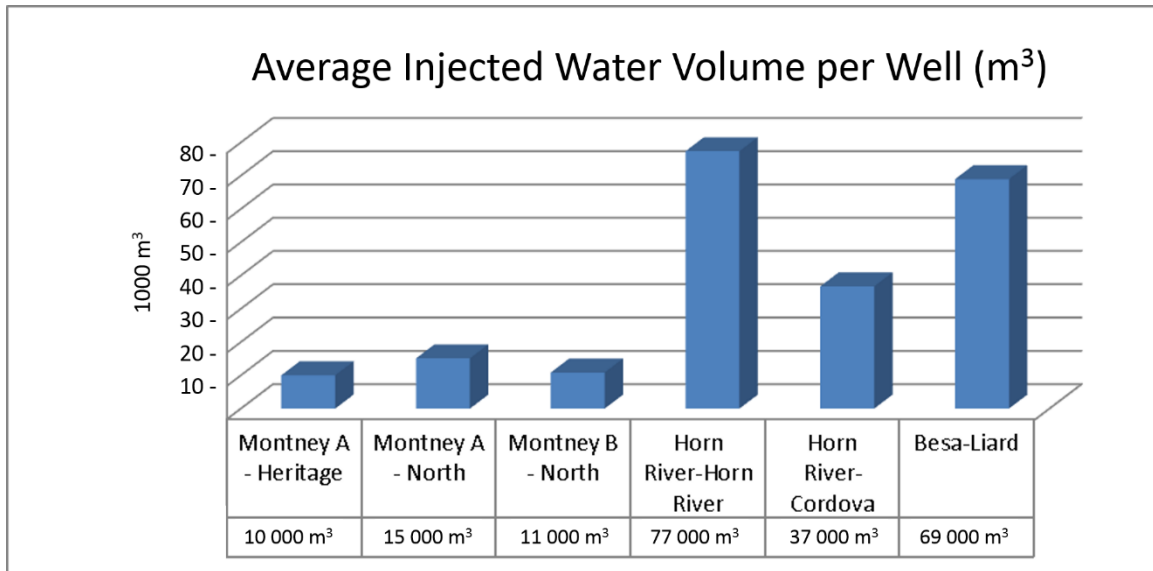
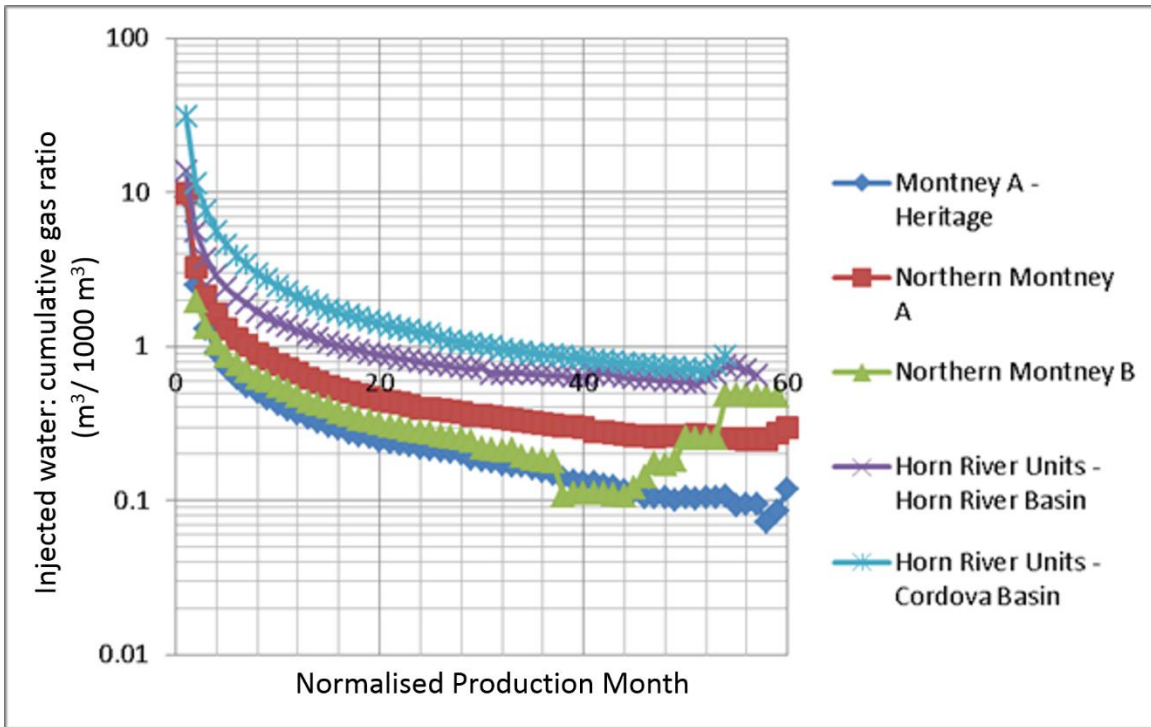Figure 5: Average injected volumes per well in each study unit.

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

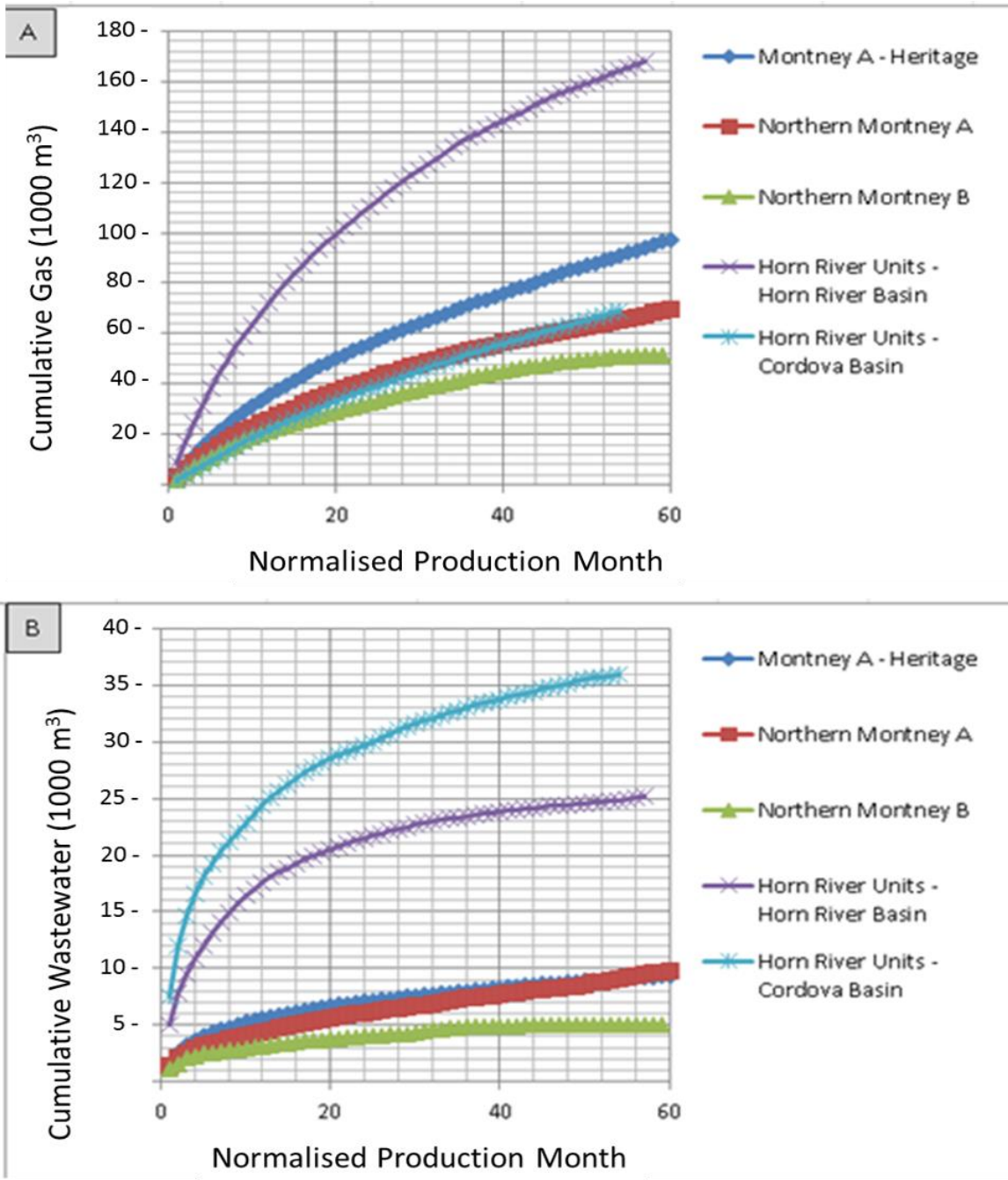Figure 7: Injected water volume during fracking divided by cumulative gas production.

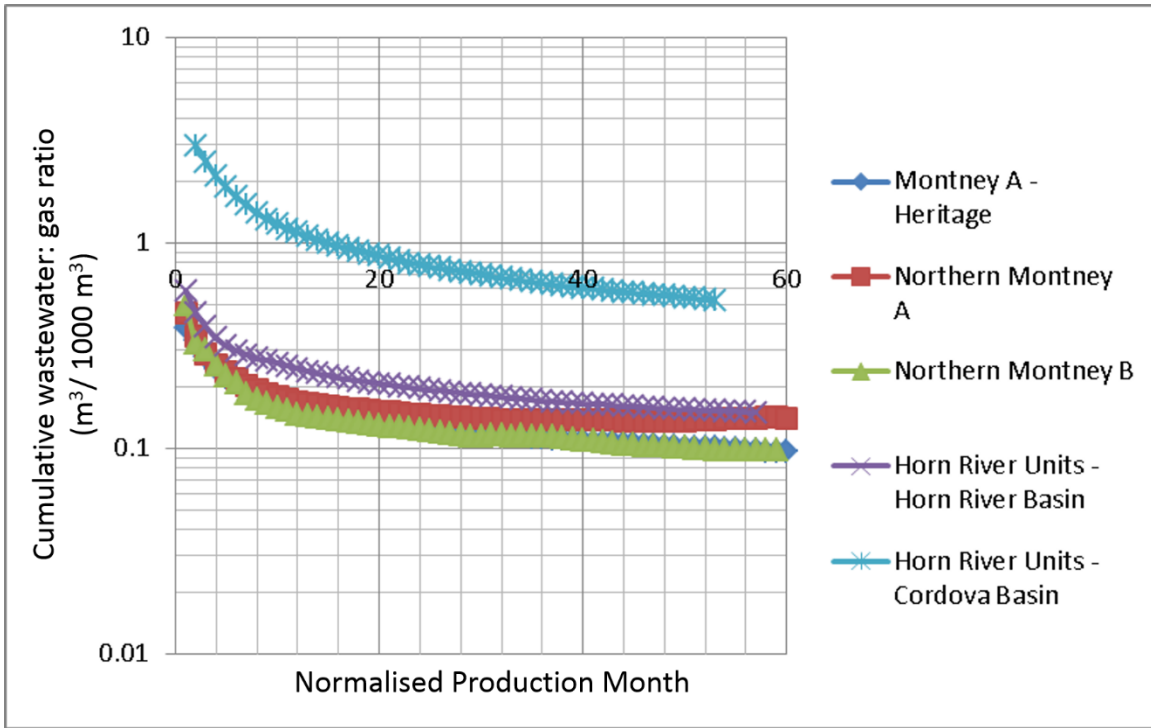Figure 8: Cumulative gas and wastewater production curves for study units.

Figure 9: Ratio of cumulative wastewater to cumulative gas production.

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

The ratios of injected water: gas and wastewater: gas presented in Figure 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).

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

Geographic Area	Study Unit	Billion cubic meters (Bm^3) of recoverable gas	Injected freshwater: gas ratio (m^3/e3m^3)	Produced wastewater: gas ratio (m^3/1,000 m^3)	Net water: gas ratio (m^3/1,000 m^3)	Injected freshwater volume (million m^3)	Produced wastewater volume (Bm^3)
Montney South (Heritage)	Montney A-South (Heritage)	4,084	0.10	0.10	0	408	408
Montney North	Montney A - North	3,209	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	2,209	0.70	0.15	-0.55	1,546	331
Cordova Embayment	Horn River – Cordova Embayment	255	0.70	0.50	-0.20	178	127

13

302 In all cases except the Montney A – south, exploitation of shale is projected to inject more water than what
303 will be produced. This is expressed by the net water: produced gas ratio which is defined as (produced
304 wastewater – injected water) / cumulative gas production ($m^3/1,000 \ m^3$). Water loss is highest in the Horn
305 River shales of the Horn River basin. Water loss is the lowest in Montney shales of the Montney south field,
306 where projected wastewater production is estimated to approximate freshwater injection needs.

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

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

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

318 Even if all wastewater produced from fracking operations were to be re-used (scenario 1), there would still
319 be the requirement to withdraw 1.6 billion cubic meters of water. Alternatively, in the worst-case scenario in
320 which no produced wastewater is re-used, 3 billion cubic meters of water would need to be withdrawn.
321 Additionally, the worst-case scenario would generate 1.3 billion cubic meters of wastewater requiring deep
322 disposal. In the most likely scenario where 40% of fracking fluids are derived from recycled wastewater, the
323 projected volume of freshwater withdrawals is similar to the best-case scenario at 1.8 billion cubic meters.

324 Assuming that 40% of injectedwater were to be sourced from produced wastewater, as suggested in the third
325 scenario, deep disposal could be entirely avoided within the Horn River basin. This is important, as there is
326 much less capacity for deep disposal in that study unit than in the others (absence of depleted permeable
327 formations). Alternatively, this is the geographic zone with the highest demand for freshwater extraction.
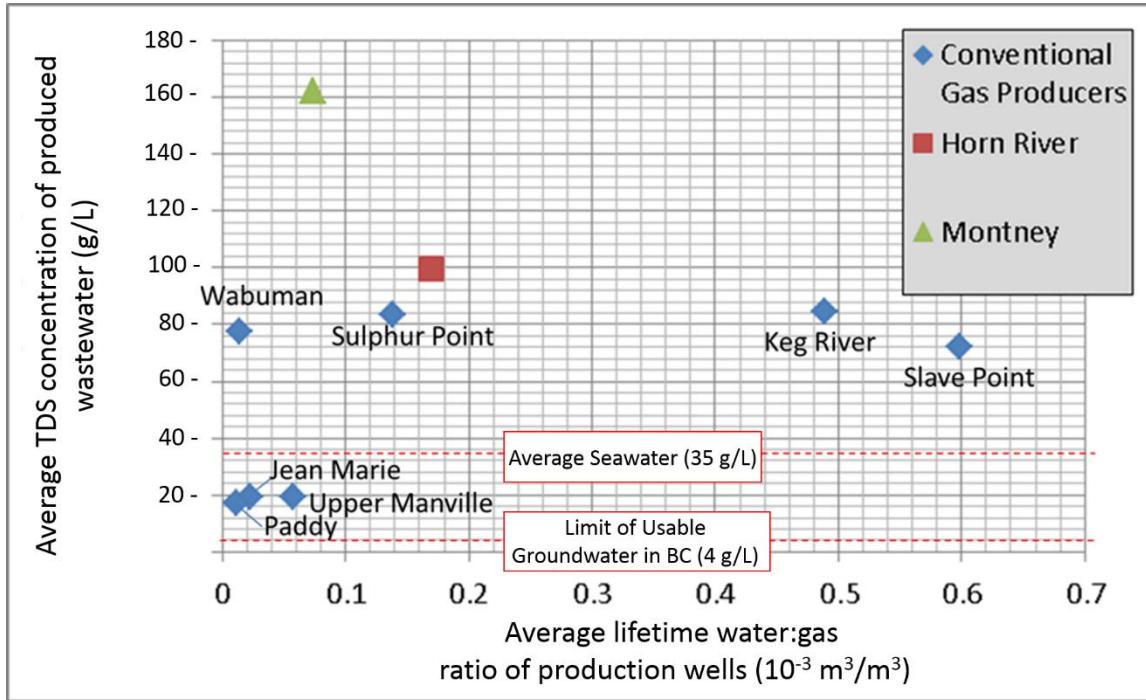
328 Table 3: Scenarios of wastewater re-use and corresponding projected volumes of freshwater withdrawal
329 and wastewater requiring deep disposal.

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	1,215	0	1,546	331	928	0
Cordova Embayment	51	0	178	127	107	56
Total	1,654	0	3,005	1,351	1,803	436

330

4.5 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 (Figure 10). However, the quality is much lower if total dissolved solids (TDS) is used as the sole criteria (Figure 10). The average TDS for produced wastewater from the Horn River and Montney units is 100,000 and 162,000 mg/L, respectively (IRIS 2018).

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

5 Discussion

The exploitation of the remaining shale reserves in British Columbia will require between 1,65 and 3 billion cubic meters of freshwater. These figures represent 2 to 4 % of the total annual flux of surface water runoff in Northeastern British Columbia, which is estimated at around 120 billion cubic meters 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 meters of 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 to 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

355 permits to oil and gas companies based on their evaluation of the potential impact of production over short-
356 and long-term periods. These permits may be revoked in times of low stream flow or drought. In British
357 Columbia, these water withdrawals are also subject to the environmental requirements of the province's
358 *Water Sustainability Act.*

359 Concerning the production of wastewater, the results of this study demonstrate that hydraulically fractured
360 wells do not generate more wastewater than conventional oil and gas wells in British Columbia. Nevertheless,
361 the growth of the shale gas industry in the province will consequently increase the volume of wastewater
362 generated, which will require either permanent disposal or re-use in subsequent hydraulic fracturing
363 operations. Currently, the best option for the permanent disposal of these wastewater is deep injection into
364 permeable saline formations containing groundwater unfit for human consumption. However, the increase in
365 reservoir pressure generated by deep disposal wells injecting wastewater has been known to trigger seismicity
366 throughout Canada and the United States (Rubinstein and Mahani, 2015). The increase in hydraulic head of
367 the disposal formation also increases the possibility of ascending cross-contamination if a hydraulic
368 connection was to exist or be created between the surface and the disposal formation (Wisen et al., 2019).

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

374 Finally, it must be underlined that very few studies in other parts of the world have addressed the issue of
375 water footprint in terms of quantifying the volumes of freshwater that are needed for hydrofracking and in
376 terms of volumes of wastewater resulting from the exploitation and future exploitation of unconventional
377 gas. This makes it difficult to conduct a comparison of the results of our study against those of other studies,
378 with the intent to provide a critical analysis on our research results. For example, Warner et al. (2013) as well
379 as Olmstead et al. (2013) have addressed the issue of the impacts of shale gas wastewater disposal on the
380 surface water quality in Pennsylvania. These two studies have shown increased concentrations of chloride
381 and bromide and high levels of contaminants in the surface waters surrounding the region of the Marcellus
382 shale gas basin. They reported TDS concentrations of shale gas waste waters comprised between 0.8 and 300
383 g/L, which results agree with the TDS concentrations observed in our study (Figure 10), namely, between
384 100 and 160 g/L for the Horn, and Montney basins, respectively. According to the same authors, the overall
385 estimated volume of oil and gas wastewater has increased during recent years to reach values between 3.1
386 and 3.8 million m^3/y. Concerning the reuse of waste water, Warner et al. (2013) as well as Olmstead et al.
387 (2013) reported that an estimated 70% of the flowback and produced fluids is reused. This ratio of 70% is
388 much higher than the ratio of reused water observed and documented in BC (40%); therefore, the ratio of
389 water reuse could potentially be improved in BC. Another study by Vandecasteele et al. (2015) has
390 investigated the impact of shale gas development on water resources consumption in northern Poland. This
391 study is not based on observed field results, but rather on modeling scenarios of future shale gas exploitation.
392 It estimated that water use per shale gas well would be between 8,000 and 19,000 m^3, which is lower than
393 the values that are observed in BC (see Figure 5); these range between 10,000 and 77,000 m^3 per well.

394

6   Conclusions

396 Using data from the British Columbia Oil and Gas Commission (data from approximately 3,750 wells), the
397 present study examines the volumes of freshwater injected and the volumes of wastewater produced in the
398 context of hydraulically fractured gas wells in northeastern British Columbia, Canada. A methodology was

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

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