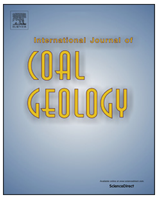
International Journal of Coal Geology 224 (2020) 103476

Contents lists available at ScienceDirect

International Journal of Coal Geology

journal homepage: www.elsevier.com/locate/coal



Post-well stimulation allocation of commingled production using geochemical fingerprinting techniques in unconventional reservoirs: A review of methods, and a case study of the Montney Formation, Western Canadian Sedimentary Basin

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ARTICLE INFO

Keywords:
Geochemical fingerprinting
Unconventional reservoirs
Allocation
Commingled
Montney
Western Canadian Sedimentary Basin

ABSTRACT

The methods used in allocating commingled production in conventional reservoirs are similar to those that are effective in performing the same task on unconventional reservoirs. However, the protocols to follow can vary a great deal. The presence of distinct endmembers in the former allows the use of the method of production allocation using peak height ratios and mixing curves and using linear regression of peak heights. Due to the possible contribution from multiple intervals in the same formation or even from different formations as in the case of fracture stimulated unconventional reservoirs, the combined application of methods that compare the quantities and carbon stable isotopes of selected compounds (such as saturate and aromatic hydrocarbons) and other parameters (such as API gravity) was employed. This was done based on a series of samples presumed to represent the endmembers via their HRGC and GCMS oil fingerprint, followed by the determination of the contribution from each sample by using an algebraic solution of simultaneous linear equations. A review of the two methods is provided.

The aforementioned method for unconventional resources is demonstrated in a case study of production allocation that was performed on three produced oils sampled at different times from three separate wells, “A” “C”, and “D”, located in the Western Canadian Sedimentary Basin. A total of 25 core extract samples representing two producing zones (end members) of the Montney Formation (i.e., the Middle and the Lower Montney) from well “A” and “B” were used. Results of GC and GCMS analyses of the samples were evaluated; rigorous filters, cluster analysis (dendrograms), and Principal Component Analysis (PCA) were applied to identify any clustering or variation between the samples representing possible contributor layers and the commingled oil. Then, using proprietary software and statistical techniques, the fingerprint of selected compounds was qualitatively compared and their quantity in each of the rock extracts and the produced oils was determined in order to allocate the contribution from the two end members that each extract belongs to.

Results from the method for unconventional resources were compared to other data (such as GC trace patterns) for consistency. The case study demonstrates that a combined approach that accounts for the entire fingerprint (i.e., GC and molecular markers (including biomarker and non-biomarker parameters)), produces the best results and minimizes uncertainty.

1. Introduction

Conventional oil and gas resources are those trapped in sedimentary strata with high porosity and permeability, and where the trapped hydrocarbons are produced under pressure and gravity and/or with the help of “low-volume” artificial fracturing, commonly known as “hydraulic fracturing” or “fracking”. In contrast, in unconventional resources hydrocarbons are contained in strata having very low porosity and permeability. Because of this, artificial stimulation in the form of “high-volume” artificial fracturing is required to create avenues for the hydrocarbons to be produced economically (e.g., King, 2012; University of Colorado brochure on Hydraulic Fracturing etc., 2019).

Commingling or commingled flow is used to describe the production of fluid from two or more separate pay zones/intervals through a single

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https://doi.org/10.1016/j.coal.2020.103476
Received 30 December 2019; Received in revised form 26 March 2020; Accepted 6 April 2020

conduit. With producing conventional wells, the production is commingled from two or more reservoirs, whereas in unconventional wells, it is often one tight reservoir or a hybrid play (where there are stacked different layers from the same formation having different porosity and permeability, for example as in the case of plays in the Permian Basin, Texas, or in the Bakken Formation, Williston Basin, North Dakota).

In the case of unconventional wells, hydraulic fracturing opens up existing fractures and creates new fractures within the target zone and surrounding intervals. As a result, multiple zones could potentially contribute to the overall production. Allocation of commingled production is required to determine which zones are contributing and also how much. This is accomplished by evaluating the natural hydrocarbon compositional variations in the produced oils or rock extracts.

Since the late 1990s, production allocation methods were applied mainly to conventional wells (Kaufman et al., 1990; Hwang et al., 2000; McCaffrey et al., 1996). According to these studies, the contributing reservoirs (end members) in conventional wells are usually distinct and known. Thus, allocation of commingled production in conventional wells is simple and involves already established methods (Kaufman et al., 1990; Hwang et al., 2000; McCaffrey et al., 1996).

Far more published and peer-reviewed studies exist on allocation of commingled production in conventional resources than the few or limited counter parts on unconventional plays (e.g., tight sands and shale, hybrid plays).

More recently, the researchers who proposed those methods used in conventional wells, and also other researchers, modified the methodology in order to apply it to the allocation of commingled production in unconventional wells (McCaffrey et al. (1996), Liu et al. (2017), and Jweda et al. (2017). This modified approach accounts for the possible contribution from multiple intervals in unconventional reservoirs in the absence of distinct end members. Time-lapse geochemistry (TLG) involves the geochemical (fingerprint) matching of fluid samples collected periodically over of a period of time during the production life of wells to core data. The time series produced fluids carry valuable information that allows us to understand from which end members the production is coming from in unconventional plays. TLG also helps to reveal the temporal and spatial variation as well as the drainage efficiency of the rock volume around horizontal wells (e.g., Liu et al., 2017).

The purpose of performing allocation of commingled production is to better understand and manage the production from the well. Allocation will also assist in field planning and development (e.g., number and location of infill wells) and completions design, including fracture height and possible migration paths (e.g., Adams et al., 2010; Larter and Aplin, 1995).

2. Previous studies

Geochemistry-based methods for allocating commingled production have long been developed, such as for allocating production in a single well which produces hydrocarbons from a number of zones (Kaufman et al., 1990), and also allocation of commingled production in a multi-sourced pipeline distribution system (Hwang et al., 2000), and analysis of ratios of peak heights (Nouvelle et al., 2012).

In conventional wells, the presence of distinct endmembers allows the use of the method of production allocation using: (a) peak height ratios and mixing curves (Kaufman et al., 1987 and 1990; Hwang et al., 2000) by comparing High-Resolution Gas Chromatographic (HRGC) fingerprints of the commingled oil with that of its two end-member oils and a 50:50 artificial mixture of the two end-member oils, and (b) using linear regression of peak heights (McCaffrey et al., 1996), which involves comparison of GC peak heights of the endmember oils and the commingled oil using linear regression and matrix algebra. The McCaffrey et al., 1996 approach does not require artificial mixtures and is applicable to multi pay zone scenarios, which was the drawback of older approaches by Kaufman et al. (1987 and 1990)).

In unconventional wells, it is possible to have contribution from multiple intervals in the same formation or even from different formations depending on fracture vertical height and horizontal length. Therefore, all the possible contributing zones must be represented (e.g., oil shows, extracts) when performing the allocation of produced oils. Methods that have been used include Adams et al. (2010), McCaffrey and Baskin (2016), Liu et al. (2017), and Jweda et al. (2017). The methods applied to allocation of unconventional sources rely on the use of the concentration (ppm) of certain compounds (tracers) (including alkanes, isoalkanes, saturates, and aromatic molecular markers) selected from GC and GCMS analyses, Liquid Chromatography (LC), whole oil/saturate/aromatic stable carbon isotope values, as well as chemical and isotopic composition of water. Adams et al. (2010) suggest whole oil or extract analyses are more effective than analysis of saturate and aromatic fractions isolated by LC. By comparing values of these parameters in the different end members with the values of the produced hydrocarbons (oil or gas), and by applying various filtering, statistical analyses (such as principal component analysis (PCA) and cluster analysis (dendrograms)) (e.g., Adams et al., 2010), and simultaneous linear equations, the contributing zones can be identified and the contribution quantified.

These methods have been applied to various conventional and unconventional productions over the years. The above methods will be applied to the unconventional resource case study described below.

2.1. Current study

Geochemistry-based allocation was performed for the commingled production in three horizontal wells from two contributing zones in the Montney Formation (a tight oil and gas shale) (i.e., the Upper and Lower Montney zones) (Fig. 1). Multiple (stacked) pay zones exist within the larger envelop, which were individually sampled for evaluation via the molecular data of their extracts, and quantification of their contribution. The data were differentiated into populations, which ultimately was helpful for determining production allocation. Also, time-lapse geochemistry techniques were applied to evaluate variations in the contribution from each zone over a period of time to the commingled production in the three wells.

The novelty of this study is based on: (a) the rigorous statistical filtering and analysis it implements in addition to what has been used in previous similar studies, (b) a much larger number of compounds used to perform the allocation, and (c) unlike other similar studies, we had the benefit of using samples (extracts) from the same well as the produced oils, and also from adjacent wells.

3. Geology and setting

The wells from which the samples in the current study originate were drilled in the Montney Formation in the Western Canadian Sedimentary Basin (WCSB). According to the Canada Energy Regulator (CER), the WCSB is one of the two major oil and gas producing basins in Canada. The Lower Triassic Montney Formation is composed of siltstone, shale, carbonates, and sandstone (Wood, 2013). Stratigraphically, it is comprised of the Upper, Middle, and Lower Montney members (Davies et al., 1997). The Montney Formation is a major productive unconventional oil and gas tight resource developed by use of horizontal drilling and hydraulic fracturing (BCOG, 2015). Petroleum systems also exist in the middle member, but the majority of the recent exploration and production activity is focused in the Upper and Lower Montney reservoirs (Zonneveld et al., 2011). The Montney Formation has a potential of 449 trillion cubic feet (TCF) (about 12,715 billion cubic meters (BCM) of natural gas, 14.5 billion barrels (2.3 Sm^3 (standard cubic meters)) of natural gas liquids, and about 1.2 billion barrels (0.19 Sm^3) of oil (National Energy Board of Canada, 2013).

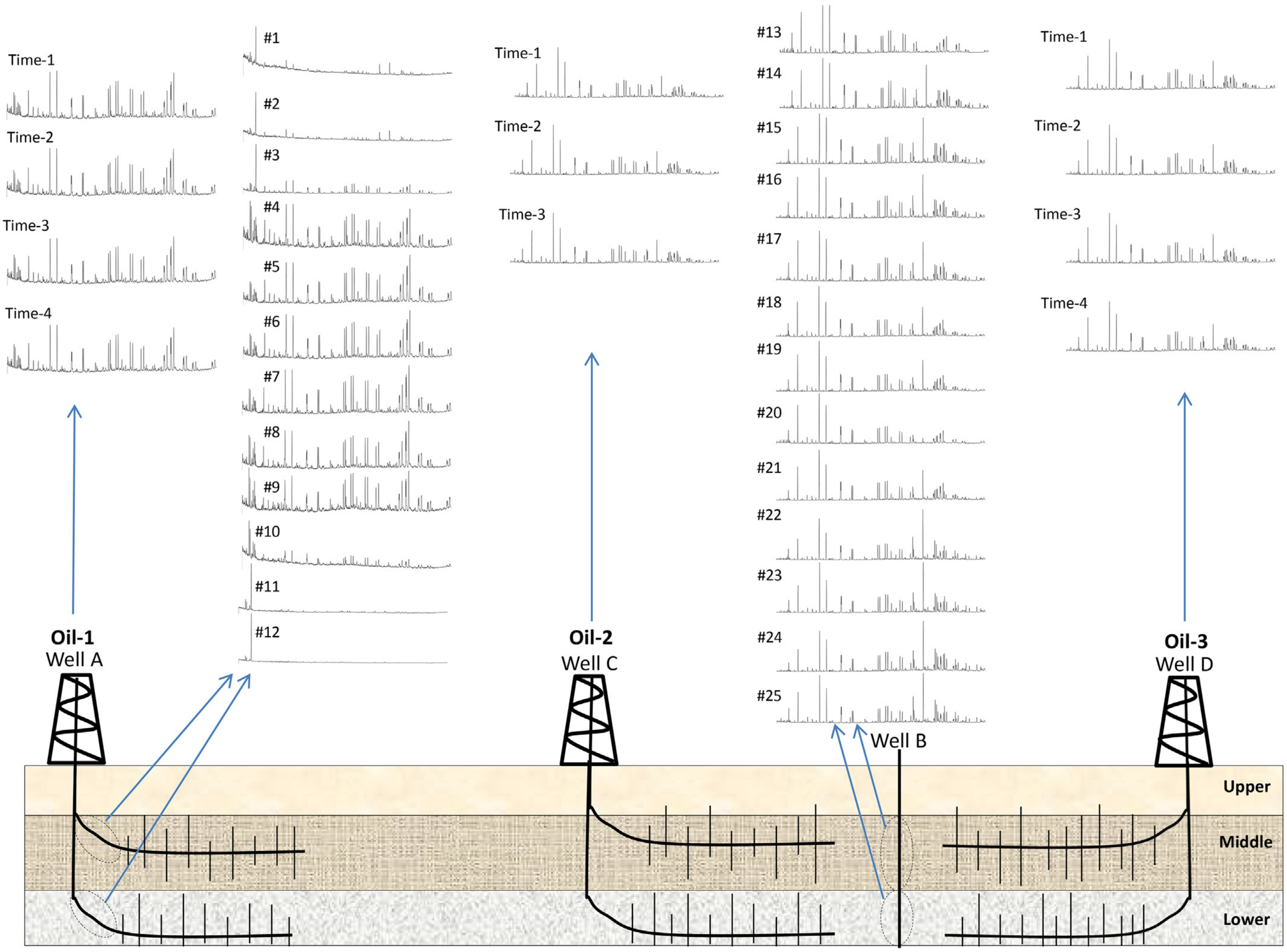

Fig. 1. Saturate fragmentograms in the *m/z* 191 (Tri- and Pentacyclics) for oils-1 to 3 sampled at different times, and extracts #1 to #25. (figure not to scale)

4. Sampling and analytical methods

4.1. Sample selection

A total of 11 oils from three produced oils sampled at different times from three wells “A”, “C”, and “D”, and 25 rock extracts from samples in two wells “A” and “B” in the Montney Formation were analyzed.

The produced oils are thought to come from the commingled production of two reservoir zones in the Montney Formation, i.e., Lower Montney and Middle Montney, and the rock extracts are from samples representing the zones that are thought to contribute to the production of the oils. Samples #1 to #12 are thought to represent the reservoirs that contribute to oil-1 which was sampled at four different times in well A. Likewise, samples #13 to #25, which were sampled from well B, are presumed to represent the zones that contribute to oils-2 and 3, which again were sampled at three and four different times, in wells C and D, respectively. Contributing zones were sampled prior to fracture stimulation of the wells.

Table 1a and 1b show the list of the samples. Oil-1 was sampled in well A at four different times namely time-1, time-2, time-3, and time-4. The same is also true for oil-2 (which was sampled three times on different dates, namely time-1, time-2, and time-3 in well C), as well as oil-3 (which was sampled on four different dates, and denoted as time-1, time-2, time-3, and time-4 in well D) (see also Fig. 1). Therefore, a total of 11 produced oils were sampled over a period of many months in the three wells, which allowed for TLG (Time Lapse Geochemistry) analysis

Table 1a
List of core extract samples and the end member they represent.

Sample ID	Well name	From end member
1	A	Middle Montney
2	A	Middle Montney
3	A	Middle Montney
4	A	Middle Montney
5	A	Middle Montney
6	A	Middle Montney
7	A	Middle Montney
8	A	Middle Montney
9	A	Lower Montney
10	A	Lower Montney
11	A	Lower Montney
12	A	Lower Montney
13	B	Middle Montney
14	B	Middle Montney
15	B	Middle Montney
16	B	Middle Montney
17	B	Middle Montney
18	B	Middle Montney
19	B	Middle Montney
20	B	Middle Montney
21	B	Middle Montney
22	B	Lower Montney
23	B	Lower Montney
24	B	Lower Montney
25	B	Lower Montney

Table 1b
List of produced (commingled) oil samples.

ID	Well name	Description
Oil-1-1	A	Oil 1 produced at time 1
Oil-1-2	A	Oil 1 produced at time 2
Oil-1-3	A	Oil 1 produced at time 3
Oil-1-4	A	Oil 1 produced at time 4
Oil-2-1	C	Oil 2 produced at time 1
Oil-2-2	C	Oil 2 produced at time 2
Oil-2-3	C	Oil 2 produced at time 3
Oil-3-1	D	Oil 3 produced at time 1
Oil-3-2	D	Oil 3 produced at time 2
Oil-3-3	D	Oil 3 produced at time 3
Oil-3-4	D	Oil 3 produced at time 4

to be performed. The oils were collected at the wellhead, and were sent to the lab in canisters as soon as they were sampled, thus no time lapsed in order to prevent samples being compromised through evaporation or contamination.

4.2. Methodology

Soxhlet extraction was used to recover bitumen from the 25 core samples (end members) from wells A and B which are thought to represent the contributing horizons with in the Lower and Upper Montney reservoirs. Crushed rock samples were extracted using organic solvents for 48 h (to ensure complete dissolution of bitumen and mobile hydrocarbons) with an azeotropic mixture of DCM-methanol (87:13).

All rock extracts and samples of produced oil underwent traditional laboratory analyses using High Resolution Gas Chromatography (HRGC), Gas Chromatography Mass Spectrometry (GCMS), Medium Pressure Liquid Chromatography (MPLC), and stable carbon isotope analysis of the whole oil, with its saturate and aromatic fractions. Results were organized in a detailed master central database.

Next, GC fingerprints and cross-plots of diagnostic molecular markers parameters of rock extracts were carefully and visually compared with that of the produced oils (Kaufman et al., 1990; Hwang et al., 2000). Reliable peaks that showed the greatest differences (> 10%) among the samples, as well as single component or ratios that differentiated the samples were selected to be used for the next stage of analysis.

Rigorous multi-layer statistical analysis was performed in order to avoid errors from poor quality peaks, to eliminate peaks that fell outside of the range of values for the end members and the produced oil, and to identify close association or differentiation trends. To achieve this, we used a combination of methods suggested by McCaffrey and Baskin (2016), Liu et al. (2017), and Jweda et al. (2017), and Core Laboratories internal proprietary multivariate analysis algorithm that takes into account the concentration of carefully selected compounds, Principal Component Analysis (PCA), and cluster analysis (dendrograms).

Production allocation of the oils was performed by linear regression using peaks (by height) from GC and GCMS peaks of selected compounds using a software package in each of the 25 rock extracts and a total of 11 produced oils sampled on different dates. Eventually, by matching each rock extract with its respective zone, the contribution from each zone of the Montney Formation (i.e., Middle and Lower Montney) was estimated.

TLG was performed by mapping the change with time of the contribution to the produced (commingled) oil from each reservoir (i.e., either Middle or Lower Montney).

Results from a total of 321 peaks from GC (n-alkanes, gasoline-range compounds, and isoprenoids) and GCMS (whole, saturate, and aromatic) analyses were qualitatively compared via close inspection of GC traces and various fingerprinting cross plots (e.g. those used for source, maturity, depositional environment, and age determination) of the end member extracts and the produced oils. Also, results from SARA (Saturates-Aromatics-Resins-Asphaltenes) and stable carbon isotope analyses of the whole and saturate as well as aromatic fractions were evaluated.

Similarities and differences between the analyzed extracts and oils were identified. Following an initial inspection, 59 molecular markers that adequately differentiated/grouped oils and extracts were selected (see Table 2). These 59 markers include 34 saturate compounds from

Table 2
the 59 initially selected molecular markers.

Saturate				Aromatic	
Ion	Name	Ion	Name	Ion	Name
191	C19 tricyclic terpane	217	C27 βα 20R diasterane	170	1,3,7-Trimethylnaphthalene
191	C20 tricyclic terpane	217	C28 βα 20S diasterane a	170	(1,4,6 + 1,3,5)-Trimethylnaphthalenes
191	C21 tricyclic terpane	217	C28 βα 20S diasterane b	170	2,3,6-Trimethylnaphthalene
191	C22 tricyclic terpane	217	C28 βα 20R diasterane a	170	1,2,4-Trimethylnaphthalene
191	C23 tricyclic terpane	217	C28 βα 20R diasterane b	170	1,2,5-Trimethylnaphthalene
191	C24 tricyclic terpane	217	C29 βα 20S diasterane	184	1,3,5,7-Tetramethylnaphthalene
191	C25 tricyclic terpane (a)	217	C29 βα 20R diasterane	184	1,3,6,7-Tetramethylnaphthalene
191	C25 tricyclic terpane (b)	259	C30 tetracyclic polyprenoid	184	2,3,6,7-Tetramethylnaphthalene
191	C26 tricyclic terpane (a)	259	C30 tetracyclic polyprenoid	184	Dibenzothiophene
191	C26 tricyclic terpane (b)			192	2-Methylphenanthrene
191	C28 tricyclic terpane (a)			192	9-Methylphenanthrene
191	C28 tricyclic terpane (b)			192	1-Methylphenanthrene
191	C29 tricyclic terpane (a)			198	4 Methyl Dibenzothiophene
191	C29 tricyclic terpane (b)			198	2 & 3 Methyl Dibenzothiophenes
191	C30 tricyclic terpane (a)			198	1 Methyl Dibenzothiophene
191	C30 tricyclic terpane (b)			206	2,6-Dimethylphenanthrene
191	Ts 18α(H)-trisnorhopane			206	2,7-Dimethylphenanthrene
191	Tm 17α(H)-trisnorhopane			206	(3,9 + 3,10 + 2,10 + 1,3)-Dimethylphenanthrenes
217	C21 sterane			206	(2,9 + 1,6)-Dimethylphenanthrenes
217	C22 sterane			206	1,7-Dimethylphenanthrene
217	C27 βα 20S diasterane			206	2,3-Dimethylphenanthrene
217	C27 βα 20R diasterane			206	1,9-Dimethylphenanthrene
217	C27 αα 20S sterane			206	1,8-Dimethylphenanthrene
217	C27 αα 20R sterane			206	1,2-Dimethylphenanthrene
217	C27 βα 20S diasterane			206	3,6-Dimethylphenanthrene

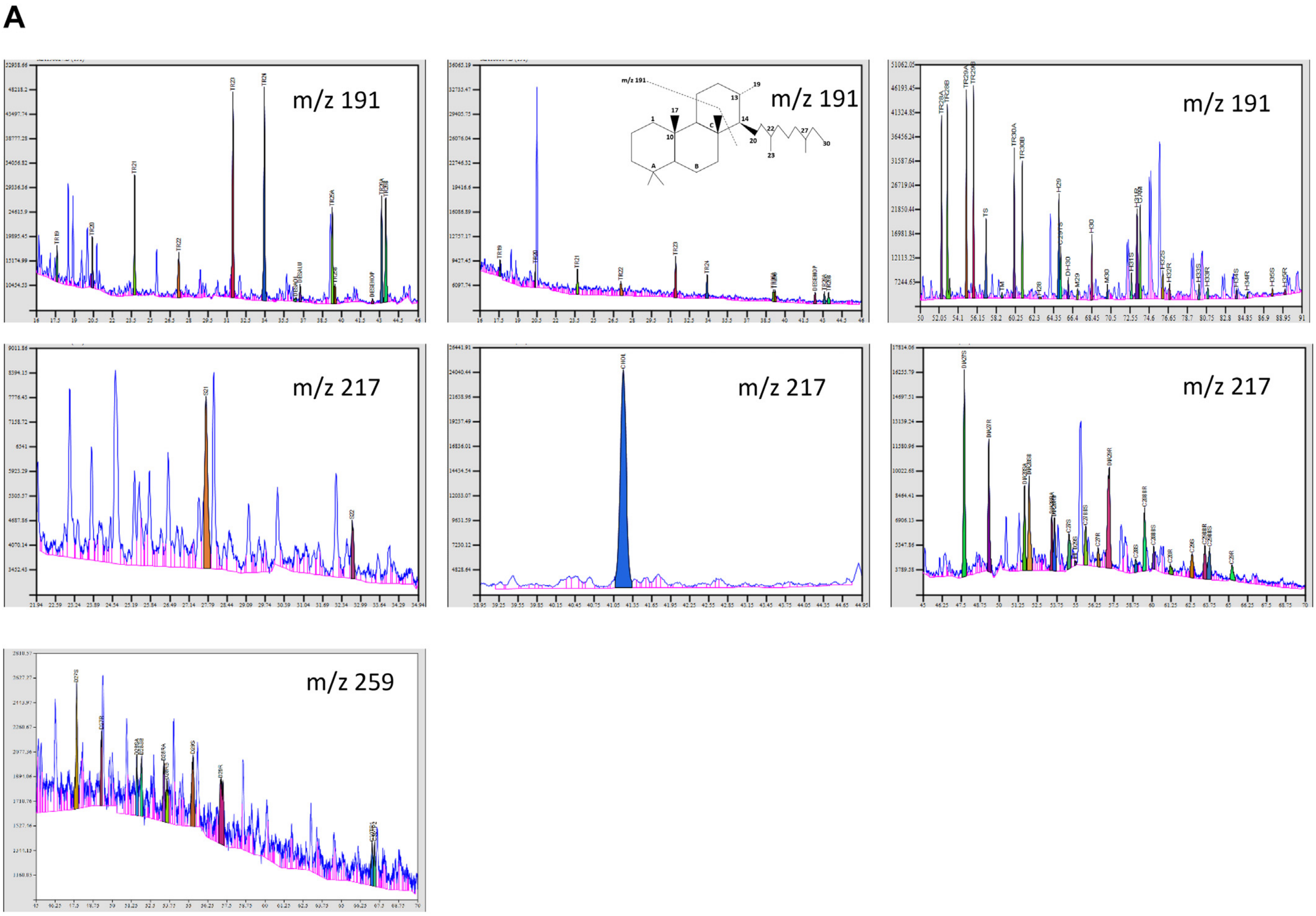

Fig. 2. a: m/z traces that comprise the selected saturates. Fig. 2b: m/z traces that comprise the selected aromatic compounds.

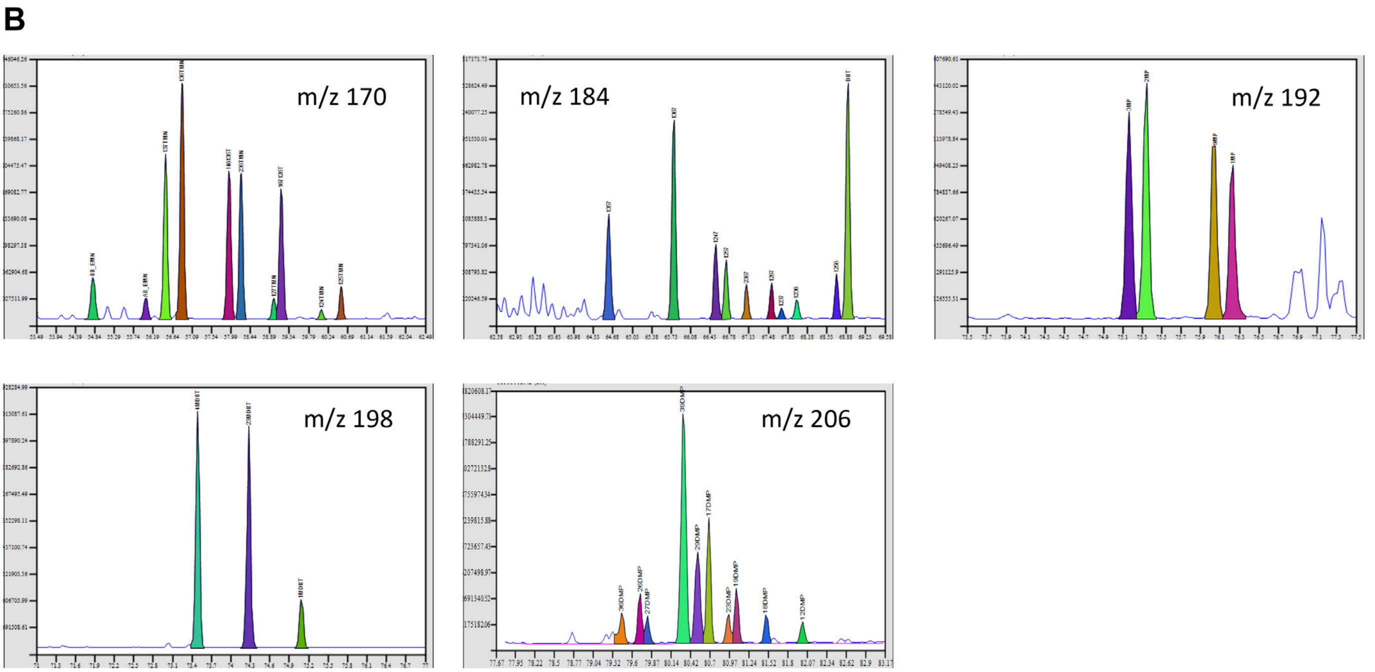

Fig. 2. (*continued*)

the *m/z* 191 (tricyclic terpanes, trisnorhopanes (Ts, Tm)), m/z 217 (steranes, diasteranes), m/z 259 (tetracyclic polyprenoids (TPPs)), and 25 aromatics from the m/z 170 and 184 (naphthalenes), DBT (m/z 184), methylphenanthrenes (m/z 192), methyl dibenzothiophenes (m/z 198) and dimethylphenanthrenes (m/z 206) (see Fig. 2a and b for m/z ion traces) (also see Table 2).

The values of these selected compounds in each of the extracts and the produced oils was then determined. If values of the end members were identical to those of the commingled oil, the selected marker compound was discarded. After normalizing and applying principal component analysis (PCA) and cluster analysis (dendrograms) with rigorous filtering, the final number of selected compounds was reduced further, from 59 to as few as 41 or as many as 57 depending on the oil. This is because those compounds that provided reliable allocation results for one oil sampled at a certain time were not necessarily the same as those for another. For example, for oil-2 sampled at time 2, only 41 of the 58 molecular markers provided reliable allocation results, whereas for oil-3 sampled at time 4, 57 out of the 58 selected compounds provided an allocation solution. For a complete set of compounds by the type of oil, the reader is referred to the supplementary material (see Appendix 3a-c).

The final percentage allocation of commingled production was computed using an array of algebraic solution of simultaneous linear equations (where the number of equations is equal to the number of extracts).

For the oils that were sampled from the same well over a period of time, TLG was performed, and stacked column charts were prepared to better demonstrate the change in contribution to the commingled oils over a period of time from each zone in the Montney Formation.

5. Results & discussion

Geochemistry-based allocation of commingled oil production is performed via comparison of natural hydrocarbon composition and distribution in the produced oil and the end member oils/extracts presumed to have come from the contributing reservoirs. In an unconventional well, the geochemical data relied upon to make this comparison must include the entire fingerprint results (i.e., stable carbon isotope of whole oil and saturate/aromatic fractions, SARA, GC, GCMS data (GCMSMS data if available), and analysis of produced water).

In the current case study, not all of the results from various analyses mentioned above adequately differentiate the samples and provide reliable production allocation solutions. For the extracts from end member samples, GC results showed the effect of evaporation (based on a depletion during extraction of gasoline-range compounds (*n*C6 to *n*C9) upon visual inspection of their GC traces), thus GC and SARA data were not reliable. Extracts from rocks tend to be depleted in gasoline-range compounds, which is the case here for the 25 Montney core extracts. Because the oils have similar origin, the saturate and aromatic carbon stable isotopes did not differentiate them adequately either. As produced water was not available, analysis could not be made. Thus, the discussion will focus only on the 41-59 (depending on the oil)selected saturate and aromatic compounds mentioned above because they differentiated the samples in a way that was helpful to perform production allocation.

5.1. Well A (oil-1)

Dendrograms and PCA analyses using data from the selected compounds (see Figs. 3a and b, and Appendices 1a and 2a-d) plot samples #1 and #2 (both from the Middle Montney end member) and #9, #10, #11, and #12) (which came from the Lower Montney end member) the closest to oil 1 sampled at times 1 to 4 (see Fig. 1). This is an indication of their similarity in origin to the oils, and possibly a greater contribution relative to the rest of the samples. Based on the allocation results (see Table 3), however, it is only samples #1, #2, #3, #4, and #8 (from the Middle Montney end member) and #9 (from the Lower Montney end member) which provided a solution, indicating that the zones that these samples represent were the only contributors during the time period the oils were sampled. The number of selected compounds that gave allocation solution were 44, 45, 42, and 43, for oil-1 sampled at times 1, 2, 3, and 4, respectively (also see Appendix 3a for the list of compounds used for PCA and dendrograms, by oil and sampling time). In this oil, and all the subsequent oils discussed below, the PCA similarity analysis is based on the distance along the PC1 axis as the % of variance is the highest along that axis (96.7% in this case) (see for the eigenvalues in Appendix 4).

Oil-1 sampled at time 1 has 17%, 46%, and 37% contribution from samples #3, #4, and #9, respectively. Oil-1 sampled at time 2 has a slightly more diverse source, where samples #1, #3, #4, and #9 have all contributed at 4%, 14%, 43%, and 39%, respectively. Oil-1 sampled at time 3 has similar contributors as oil-1 at time 2, with percentage of contribution of 11%, 30%, 26%, and 33%, respectively. There was a shift in source during the accumulation of oil-1 sampled at time 4, where contribution came from zones for samples #2, #8, and #11, at 21%, 60%, and 19%, respectively. Contribution of sample #11 was evident only in oil-1 sampled during time 3.

Overall, during the time oil-1 was sampled at different times, contribution from the Middle Montney endmember (ranging from 61 to 81%, with a minimum and maximum in oil-1 sampled at time 2 and 4, respectively) was greater than the contribution from the Lower Montney end member (which was 19–39%, with a minimum and maximum in oil-1 sampled at time 4 and 2, respectively) (see Table 4). The zone in Lower Montney end member from which sample #9 came from seems to be a potential one as it contributed in the production of all oil-1 oils sampled at times 1 to 3 in well A. Likewise, the zone in Middle Montney end member from which samples #3 and #4 came from seems to be productive. The period during which oil-1 at time 4 was generated is unique as there were new contributing zones than the other three oils. Based on the allocation results, samples #5 to #7, #10, and #12 appear to have no contribution at all to the produced oil-1 oils sampled at times 1 to 4 in well A.

5.2. Well C (oil 2)

Results from the statistical analyses (PCA and dendrograms) in Fig. 3a and b, and Appendices 1b and 2e-g show that oil-2 sampled at times 1 and 2 plot closest to samples #14, #15, #16, and #17 (all from the Middle Montney end member) and #22, #23, and #24 (all from the Lower Montney end member). Oil-2 sampled at time 3 is slightly different and plots very close with sample #25 (indicating a strong relationship, such as a similar origin and greater contribution); oil-2 sampled at time 3 also plots close to samples #13, #18, #19, #20, and #21 (all from the Middle Montney end member).

As shown by the allocation results (see Table 3), of the samples that represent the Middle Montney end member, only samples #13, #14, #16, and #18 show contribution during the production of oil-2 sampled at times 1, 2, and 3 (see Fig. 1). But even these samples did not contribute in a consistent manner; for example sample #13's contribution was only recorded in oil-2 sampled at time 3, sample #14 contributed to all of the three oil-2 samples sampled at different times, sample #16 contributed to oil-2 sampled at time 2 only, and sample #18's contribution came only during the period oil-2 sampled at times 2 and 3 accumulated. Furthermore, there are Middle Montney samples such as #15, #17, and #19 to #21 which seem to have no contribution at all.

The number of selected compounds that gave allocation solution in oil-2 were 44, 41, and 40, for sampling times 1, 2, and 3, respectively (also see Appendix 3b). The eigenvalues of the PCA components are provided in Appendix 4.

Among the samples that represent the Lower Montney end member

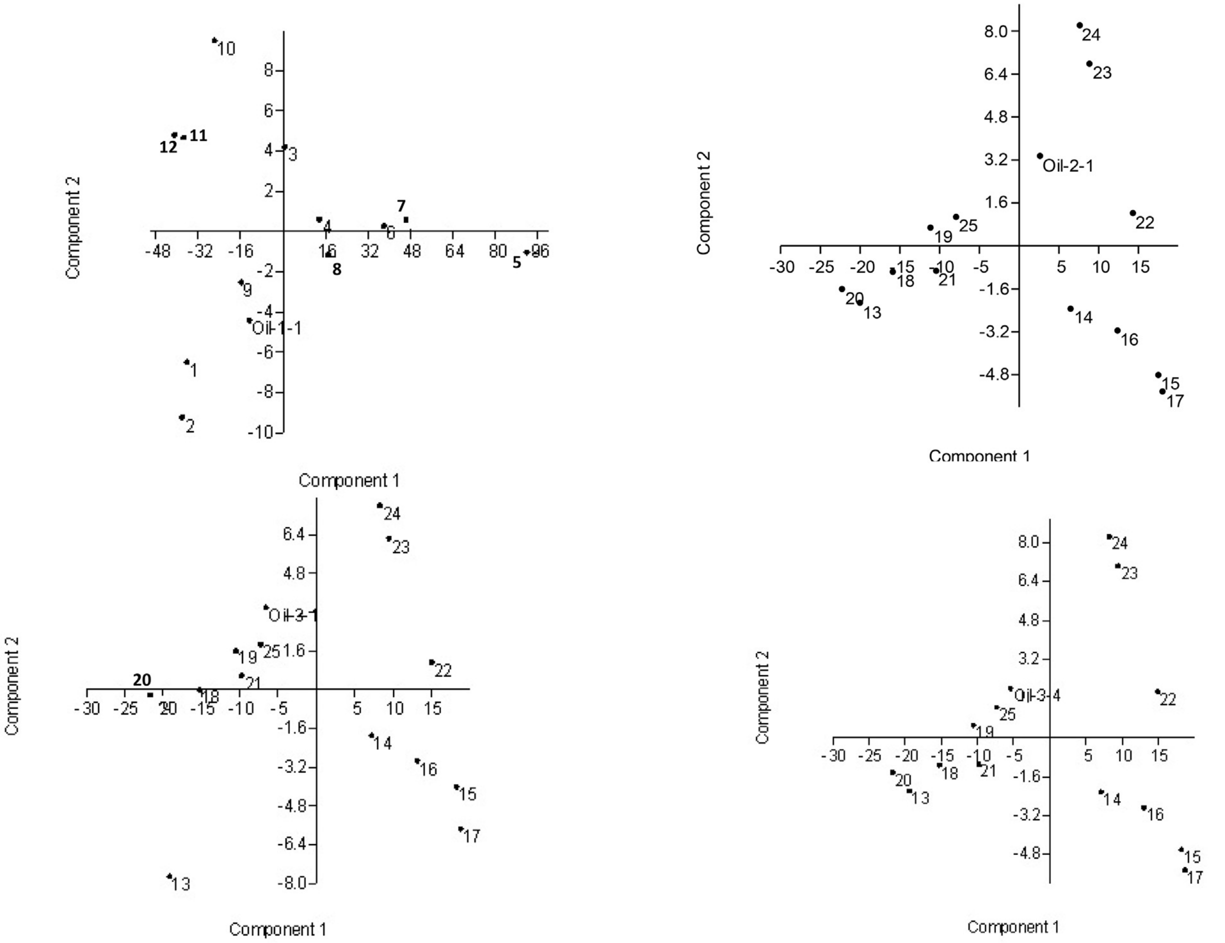

Fig. 3. a: A sample of Principal Component Analysis (PCA) plots for oils 1 to 3, sampled at different times (see Appendix 1a to c for the full display of PCA plots). Fig. 3b: A sample of cluster analysis (dendrogram) plots for oils 1 to 3, sampled at different times (see Appendix 2a to k for the full display of dendrogram plots).

(i.e., #22, #23, #24, and #25), only #24 did not have any contribution at all to any of the oils in well C; the rest of the samples all had a contribution (albeit not a consistent one). Sample #22 only contributed to oil-2 sampled at time 1. Sample #23 contributed to both oil-2 sampled at times 2 and 3, but not to oil-2 sampled at time 1. Sample #25 is the only one which had a contribution to all of the oil-2 samples from times 1, 2, and 3.

Although sample #24 plots close to oil-2 sampled at times 1 and 2, it doesn't have any contribution to any of the oils as shown in Table 3. This is not an error but reflects the difference between these different statistical methods and the components they use to differentiate the samples.

The periods of peak charge were from sample #13 (in oil-2 sampled at time 3, at 22%), #16 (in oil-2 sampled at time 2, at 40%), #18 (in oil-2 sampled at time 1, at 33%) and #25 (at 37–40%). Overall, the contribution from the Lower Montney end member is slightly higher than that from the Middle Montney end member, but not by much (see Table 4).

5.3. Well D (oil 3)

Oil-3 sampled at times 1, 2, and 3 (also see Fig. 1) plot closely and are related to samples #13, #18, #19, #20, and #21 (all representing the Middle Montney end member) and #25 (representing the Lower Montney end member) (see Fig. 3a and b, and Appendices 1c and 2 h-k). As for oil-3 sampled at time 4, it has a different pattern because on the PCA and dendrograms, it plots very close to sample #25 (indicating a significant contribution from that particular horizon in the Lower Montney end member); the plots also show that oil-3-4 is related and received contribution from the part of the Middle Montney end member which is represented by samples #18, #19, #21, as well as #13 and #20).

The number of selected compounds that gave allocation solution in oil-3 were 44 for oils sampled at times 1, 2, and 3, whereas 47 for oil sampled at time 4 (also see Appendix 3c). The eigenvalues of the PCA components are provided in Appendix 4.

Just as it was observed with the other oils and representative samples discussed previously, the allocation results (see Table 3) show variable distribution of (or the lack of) contribution to the produced oils in this well from the Middle and Lower Montney end members. Samples #15 to #17 (representing the Middle Montney end member), and #22 (representing the Lower Montney end member) did not have any contribution to the produced oils. Sample #13 had a contribution to oil-3 sampled at times 1, 2, and 3, but not to the oil sampled in time 4. Samples #14 and #18 only contributed to oil-3 sampled at time 4. All of the produced oils received contribution from sample #21. Only oil-3 sampled at times 1 and 3 received contribution from sample #23. Oil-3 sampled at times 2 and 4 as well as oil-3 sampled at times 1, 3, and 4 received contribution from samples #24 and #25, respectively.

Overall, and as shown in Table 4, with oil-3 sampled at times 1, 2, and 3 in well D, the contribution from the Middle Montney end member is the greatest, unlike in the other produced oils discussed above where the opposite is true. For oil-3 sampled at time 4, however, the situation reversed and the contribution from the Lower Montney end member (at 51%, and came from two samples; #24 at 23% and #25 at 28%) again surpassed that from the Middle Montney end member (at 49%,

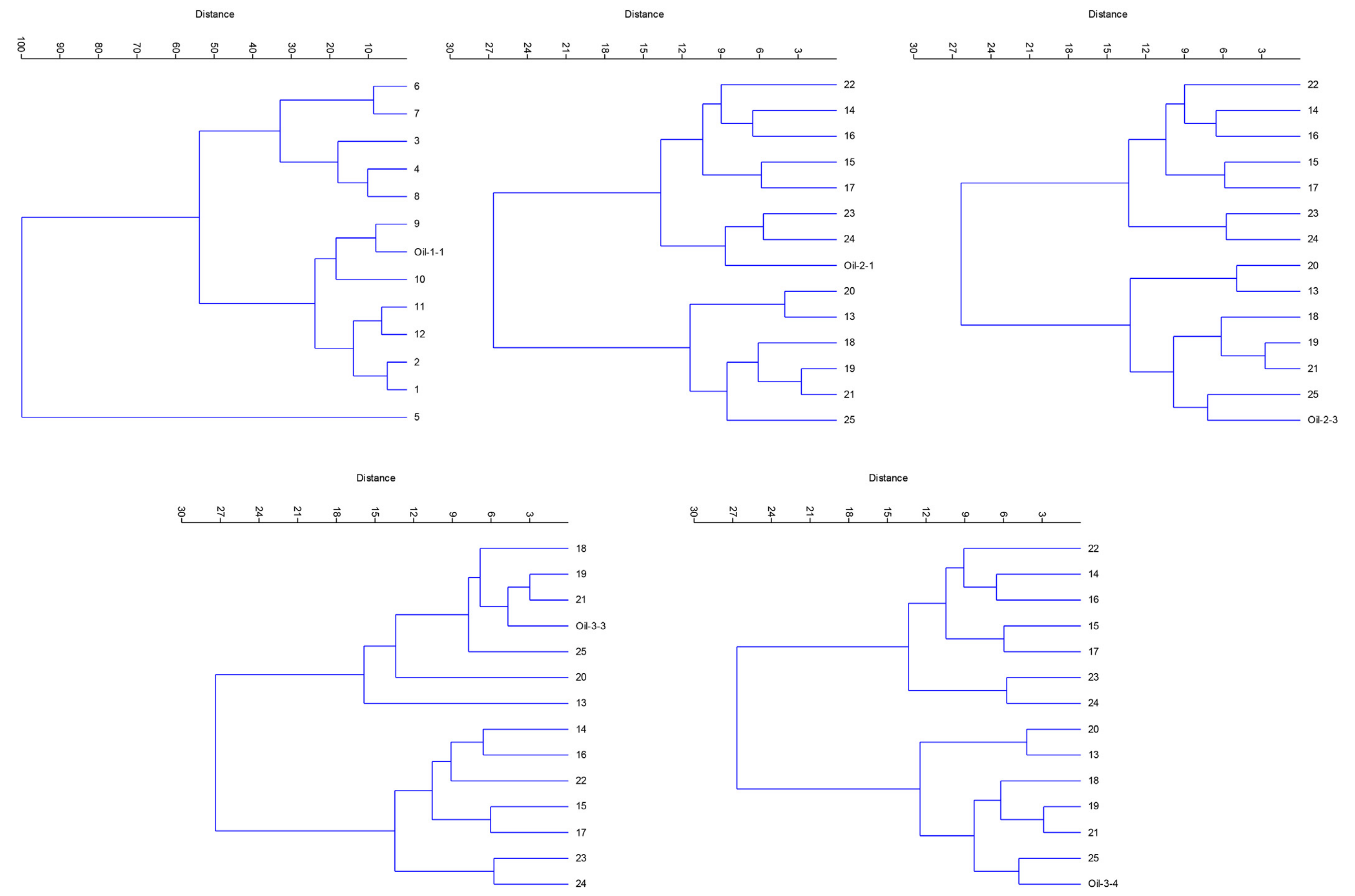

Fig. 3. (*continued*)

comprised of contributions from several samples; #14 at 6%, #18 at 24%, #20 at 10%, and #21 at 9%).

In all three wells A, C, and D, some of the samples (thus the zones they came from) do not seem to have made any contribution at all to the production of the commingled oils (see Table 3). The evidence for this is the absence of allocation solution during statistical analysis using the algebraic solution of simultaneous linear equations for representative samples from those end members.

5.4. *Time-lapse geochemistry*

Oil-1 was sampled on different dates, at times 1, 2, 3, & 4, respectively, consecutively from Well A. Likewise, oil-2 was sampled from well C at times 1, 2, and 3, one after the other, on different dates; and oil-3 was sampled from well D at times 1, 2, 3, and 4 (also see Fig. 1 for the setup).

The TLG result indicates that the contribution from both the Lower Montney and Middle Montney end members to the produced oils fluctuated during the time period the produced oils were sampled. Over the period of time the samples were collected, the contribution from the Lower Montney end member ranged from 19 to 39% in well A, 51–58% in well C, and 13–51% in well D. The contribution from the Middle Montney end member ranged from 61 to 81% in well A, and 42–49% and 49–87% in wells C and D, respectively (see Table 4).

In well A, the TLG results show that the contribution from the Middle Montney end member stayed at about the same level, except in oil-1 sampled at time 4 where it increased significantly, and exceeded the contribution from the Lower Montney end member considerably (see Table 4).

For well C, the contribution was about the same from both end members, with a slightly greater contribution from the Lower Montney end member.

In well D, allocation data indicates the Middle Montney end member was the dominant contributor. TLG showed that the contribution from the Middle Montney end member increased significantly during the time oil-3 sampled at time 2 was generated.

It is also worth noting that contribution to the commingled production from the Middle Montney end member is greater in well D than wells A and C.

Overall, the dynamic variation in the level of contribution from the two end members (i.e., the Middle and Lower Montney) to the production of oils may be related to the evolution of the fractures and the extent of the fractures above and below the horizontal well. These fluctuations could also have reasons rooted in bulk properties of the representative samples used (such as Total Organic Content, permeability, porosity, amount of extractable hydrocarbon (EOM)). Unfortunately, except for EOM (see Table 3), some of these key characteristics are not available for the samples in this study. In well A, although samples #5, #6, #7, and #8 relatively have among the highest EOM (see Table 3), they don't have any contribution to the production of oil-1 sampled at times 1 to 4. The same is true with samples #10, #11, and #12, although they may have a lower EOM, but still higher than that of some of the samples that represent potentially producing zones (especially #1 and #2). The same is also true for the absence in contribution from samples #15, #17, #19 (see Table 3).

Other potential factors that affect the presence/absence of contribution, despite the relative EOM, can be inferred (since detailed data on these aspects is not available in the current study) which include interconnectedness of migration pathways, variation in how tight interconnected avenues between mineral matrix of a rock are in those

Table 3
Allocation results. (EOM = Extractable Organic Matter)

Sample ID	Well name	End Member	EOM (mg)	Allocation & Time-lapse Geochemistry										
				Oil-1-1	Oil-1-2	Oil-1-3	Oil-1-4	Oil-2-1	Oil-2-2	Oil-2-3	Oil-3-1	Oil-3-2	Oil-3-3	Oil-3-4
1	A	Middle Montney	6.80		4	11								
2	A	Middle Montney	4.30				21							
3	A	Middle Montney	15.20	17	14	30								
4	A	Middle Montney	15.00	46	43	26								
5	A	Middle Montney	25.80											
6	A	Middle Montney	21.50											
7	A	Middle Montney	16.80											
8	A	Middle Montney	16.30				60							
9	A	Lower Montney	26.20	37	39	33	19							
10	A	Lower Montney	14.60											
11	A	Lower Montney	13.70											
12	A	Lower Montney	15.20											
13	B	Middle Montney	14.60							22	1	65	5	
14	B	Middle Montney	7.80					16	7	3				6
15	B	Middle Montney	10.60											
16	B	Middle Montney	8.20						40					
17	B	Middle Montney	6.80											
18	B	Middle Montney	3.90					33		17				24
19	B	Middle Montney	5.10											
20	B	Middle Montney	4.40											10
21	B	Middle Montney	4.80								61	22	59	9
22	B	Lower Montney	15.30					14						
23	B	Lower Montney	14.40						21	18	13		10	
24	B	Lower Montney	9.90									13		23
25	B	Lower Montney	10.90					37	32	40	25		26	28
			TOTAL	100	100	100	100	100	100	100	100	100	100	100

Well A **Well C** **Well D**

horizons which are not contributing (as opposed to those that are), vertical and horizontal fracture distribution and its evolution (i.e., both natural and induced fractures). These latter factors do not only explain the absence of contribution from certain zones that the samples represent, but can also shed light on the fluctuation (i.e., turn-on and turn-off in contribution).

There is another scenario that is worth mentioning and may explain the differences in concentration of the molecular markers in the extracted hydrocarbons (samples #1 to #25 in the current study) and the produced oils (in the current case, the produced oils 1 to 3 sampled at different times). Despite the fact that both of the extracts and the produced oils believed to have been sourced by the same horizons, past laboratory and field studies (e.g., Silverman, 1965; Mackenzie et al., 1987; Krooss and Leythaeuser, 1988 etc.) have indicated that the produced oil can change its composition due to organic compounds interacting at varying degrees with the surrounding matter during its migration (primary and secondary) through intergranular space in the matrix of the host rock, by a process called geochromatography. The way the different components of the oil behave during the migration process depends on their physical and chemical properties; whereas hydrocarbon extracted from the source rock using solvent was not exposed to the various processes associated with hydrocarbon migration (e.g., adsorption, desorption) that the produced oils faced. These differences may have impacted the allocation of contribution from each of the individual extracts in to the commingled production of the oils.

6. Conclusions

Based on the discussion of the results in the case study and the overall methods used to determine the allocation of commingled production in an unconventional well, the following remarks can be made:

- The methods used in allocating commingled production in unconventional reservoirs are similar to those used in their conventional counterparts, with the former involving a great deal of rigorous statistical treatment and detailed inspection to select compounds that can yield allocation results.
- A combined approach that accounts for the entire fingerprint (including GC and molecular markers) produces the best results and minimizes uncertainty when allocating production from unconventional wells. Of course, selecting those compounds that yield solution and help solve the problem at hand is required, such as was done in the current study where GC parameters were not utilized for allocation purpose as they showed signs of being affected by evaporation, and stable carbon isotopes didn't adequately differentiate the oils, so they were not used in the final allocation calculation.
- In the current study, arduous and careful selection of 41-59 (depending on the oil) compounds that adequately differentiated the extracts and the produced oils was key for subsequent accurate allocation results.
- As shown in the case study, the contribution from the contributing zones in the Montney Formation end members fluctuated with time, with complete reversal at times (for example: in oils-1 and 2 the contribution from the Lower Montney end member is the greatest,

Table 4

Allocation results.

Well A	**% contribution**			
End Member	Oil-1-1	Oil-1-2	Oil-1-3	Oil-1-4
Middle Montney	63	61	67	81
Lower Montney	37	39	33	19
Total	100	100	100	100

Well C	**% contribution**		
End member	Oil-2-1	Oil-2-2	Oil-2-3
Middle Montney	49	47	42
Lower Montney	51	53	58
Total	100	100	100

Well D	**% contribution**			
End member	Oil-3-1	Oil-3-2	Oil-3-3	Oil-3-4
Middle Montney	62	87	64	49
Lower Montney	38	13	36	51
Total	100	100	100	100

but in oil-3 the opposite is true, where the Middle Montney end member is the greatest contributor; but then in oil-3 sampled at time 4, the contribution reversed back to the Lower Montney end member being the greatest contributor).

- By sampling the same oil over a period of time, time-lapse geochemistry can be used to demonstrate the dynamic nature of and quantifying the temporal change in contribution to the commingled production from the producing zones. This is demonstrated in the case study presented here. This change in contribution over time may be linked to the evolution of fractures that are above and below the horizontal production well.
- It is appropriate to recognize the influence to the allocation results which can arise from the method of hydrocarbon extraction, differing end member bulk properties, as well as the effect of geochromatography. In the current study, careful selection process was performed to use organic compounds that show no or minimal effect from these adverse processes.

Acknowledgments

The authors would like to thank the organizing committee of TSOP 2019 Bloomington, Indiana for the invitation to contribute to the special issue. Our gratitude also goes to the editor-in-chief Dr. C. Özgen Karacan and guest editor Dr. Agnieszka Drobniak, for the professional manner they handled our manuscript during the review process; and the anonymous reviewers for their time in reviewing the manuscript, and their valuable comments and suggestions which greatly improved the quality of the manuscript. We also want to thank Barry Wawak, manager of Core Lab Reservoir Geology Group, for his support.

Appendix A. Supplementary data

Supplementary data to this article can be found online at https://doi.org/10.1016/j.coal.2020.103476.

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