URTeC: 2670186

# Time-lapse Geochemistry (TLG) Application in Unconventional Reservoir Development

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This paper was prepared for presentation at the Unconventional Resources Technology Conference held in Austin, Texas, USA, 24-26 July 2017.



## Summary

The use of reservoir geochemistry in field development has been well established for several years in conventional reservoirs to understand reservoir compartmentalization and fluid property distribution. However, its application to unconventional reservoirs (both source rock and hybrid plays) has been less well-documented and is often more challenging.

When interpreted geochemically, the time series produced fluid carries valuable information that reveals the temporal and spatial variation of the effective drained rock volume (DRV) surrounding horizontal wells in unconventional plays. This dynamic behavior of the DRV is crucial to various field development decisions including vertical landing targets, well spacing and stacking, and completion designs. Compared to other diagnostic technologies (e.g. microseismic, downhole pressure gauges, and fiber-optics) that are reflective of the stimulated rock volumes (SRV), geochemistry-based methods directly measure the produced fluid and therefore reveal the true DRV of the hydraulically-fractured well. ConocoPhillips has successfully deployed time-lapse geochemistry (TLG) for over 5 years across multiple North America unconventional assets, and found that collecting and analyzing fluid samples over time often indicates that drainage heights are dynamic. Here we present an overview of the application of time-lapse geochemistry in assorted North America ConocoPhillips unconventional plays, and show an example application from the Bakken/Three Forks play in the Williston Basin. The use of TLG methodologies for production allocation of oil and water will be presented for a spacing pilot through time, and the implications for field development will be illustrated.

## Introduction

Recent technology advances in horizontal drilling and hydraulic fracturing have unlocked significant resources in the unconventional plays, particularly those in shales and hybrid plays with ultra-low permeability. Since then, the industry has recognized the importance of characterizing the induced fracture network, the extent of which is crucial to the economics of unconventional reservoir development. Key technologies that have been applied include microseismic (Warpinski 2009, Cipolla et al. 2012, Cipolla 2015, Warpinski et al. 2016), chemical tracers (Catlett et al. 2013, Salman et al. 2014, Lal et al. 2017), fiber-optics (Huckabee 2009, Molenaar et al. 2012, Ugueto et al. 2014, Ugueto et al. 2016), and pressure and rate transient analysis (PTA and RTA) (Fisher et al. 2005, Blasingame 2008, Clarkson 2012, Al-hashim et al. 2013). Extensive studies have been conducted in each of the methods and readers can refer to the literature listed above for details. Most of those methods rely on physics-based parameters – pressure, temperature, and acoustic response - which are: 1) limited in variety in the subsurface environment using currently available technology, 2) indirect measurements, 3) and reflective of the SRV, not necessarily the DRV. Because thousands of naturally-occurring compounds occur in produced oil, gas, and water, and the proportions of those compounds vary spatially, compositional and isotopic geochemical analysis offers significant potential to yield insights constraining the DRV at any given point in time. Most importantly, by monitoring those chemical signature variations over time (*i.e.* the time-lapse element), we can further delineate temporal variation of the DRV (and perhaps fracture evolution) to guide development and reservoir management decisions.

Geochemistry-based techniques are well-established as reservoir characterization tools in the petroleum industry. Over the last 30 years, geochemistry has been well-developed and successfully applied in conventional reservoirs globally to solve various production issues including reservoir connectivity and compartmentalization evaluation, fluid property prediction, and production allocation (Kaufman 1990, Smalley et al. 1994, Bement et al. 1996, McCaffrey et al. 1996, Smalley et al. 1996, Henshaw et al. 1998). However, the conventional application of geochemistry is challenged by the low permeability in ultra-tight unconventional reservoirs. Production allocation techniques rely on the chemical fingerprints in each of the individual end members (i.e. produced oil from single zone) as the reference and baseline to allocate the commingled oil. Quantitative compositional geochemical information is measured in each sample. That information is then recorded and processed numerically to feed into a mixing model to calculate the contribution from each of the end members to the commingled produced oil. Due to the low-permeability, collection of pure end-member produced oil from unconventional reservoir target intervals is extremely challenging. This becomes the biggest obstacle for the application of production geochemistry in unconventional reservoirs. We have developed a method to resolve this issue by extracting the necessary end-member chemical signatures from the core extracts instead of direct produced oil sample from single end-member. We also present a successful case study in the Williston using this method.

Additionally, we present an application of TLG via chemical finger-printing using produced water. Aqueous geochemistry techniques are not commonly used in the oil & gas industry. However, the hydrogeology and geothermal communities have successfully used aqueous geochemistry from water-rock interaction for fracture characterization for many years (Moore et al. 1986, McNutt et al. 1990, Aquilina et al. 1997, Berkowitz 2002). The ions dissolved in the water, when analyzed compositionally and isotopically, provide an abundance of additional parameters to further constrain the DRV evaluation and yield insights into the multi-phase fluid flow behavior in the complex fracture network in the shale matrix. The application of aqueous geochemistry-based techniques are still at their early stage, but show promise both from internal studies (partially shown in this paper) and other investigators' work (Laughland et al. 2014, Zolfaghari et al. 2015, Bryndzia et al. 2016, Zolfaghari et al. 2016).

Over the past decade, ConocoPhillips has significantly advanced the production geochemistry techniques for unconventional plays and developed a propriety toolkit called Time-lapse Geochemistry (TLG). We have successfully applied the TLG in most of our key unconventional assets in North America including Barnett, Niobrara, Eagle Ford (Jweda et al. 2017), Bakken, the Permian Basin, and the West Canada Sedimentary Basin. In this paper, we present a case study illustrating application of the time-lapse geochemistry toolkit in the Bakken/Three Forks play to provide insights on drainage volume and its dynamic evolution through time, guiding field development decisions such as well spacing, stacking and completion designs.

## Method

The following session describes the general information on data acquisition, analytical and data processing methods of TLG that apply to most unconventional plays. Based on different rock and fluid properties (TOC content, permeability, mineralogy, *etc*.) of each specific play, the methods may be further tailored for optimized results.

### Sample Collection

Time-lapse geochemistry samples for produced oil, gas and water are typically collected simultaneously at the separator. The time period over which the sample collection occurs is variable based on the objective and local geology. In general, collection frequency is highest during initial flowback (< 1 mo.), and frequency reduces to ~25 samples per 6-12 mo. period. This allows the ability to monitor the dynamic nature of drainage heights over time and monitor for other changes in flow behavior (e.g. break out of 2-phase flow) and communication between wells. Collection of samples prior to and after shut-ins for operations or production rate sharing tests also allows for an opportunity to monitor dynamic changes in drainage.

All produced water samples are collected in transfer containers prior to processing into sample containers for the laboratory. Samples are processed by transferring the collected sample from the transfer containers to appropriate sample containers for laboratory analyses using a peristaltic pump. Precleaned, one-gallon plastic containers are used as the transfer containers.

In-situ fluid samples are extracted from the interior piece of the preserved core (20 – 40 g) that served as end-members of the allocation. The core was sampled at ~10 ft intervals.

Laboratory Analyses

*Hydrocarbon*

The methodology used in this paper refers to the use of either quantitative concentration (ppm) data or ratios calculated from concentrations derived from peak areas correlated to internal quantitative standards using gas chromatography (GC) or gas chromatography-mass spectrometry (GC-MS). The use of natural samples utilized as external standards, coupled with internal standards, allows for tracking of potential drift in the instrumentation or methodology through time and enables correction without large scale re-running of samples.

Whole rock core pieces are extracted and the extract is processed for chemical composition separation (SARA). The maltenes (saturate, aromatic and resins) are separated by liquid chromatography (MPLC). The saturate, aromatic and resins are weighed and then volumetrically diluted for analysis by GC and GC-MS.

*Water*

Chemical and isotopic analyses of constituents dissolved in the water samples are conducted. Dissolved metals are analyzed using inductively coupled plasma emission spectrometry and mass spectrometry (ICPES, ICPMS), anions were measured by ion chromatography (IC), and pH, temperature, filtration, and preservation were procedures conducted at the well site. Stable isotopic analyses of key indicator constituents are measured by mass spectrometry.

*Data Processing*

Automated generation and screening for the thousands of possible ratios (compounds and isotopes) that provide information by stratigraphic interval is facilitated by Microsoft Excel based macros. Compound ratios may be further screened based on concentration for adherence to linear mixing rules. Also, the signal for compounds used is required to be above analytical variation (Nouvelle and Coutrot, 2010). The basis of quantitative production allocation is matrix linear algebra solutions with modification in order to handle large matrices and explore uncertainty around a non-unique solution (McCaffrey et al., 1996, Nouvelle et al., 2012).

**Case Study – Bakken/Three Forks Play, North America**

Geological Setting

The Williston Basin is an intracratonic basin with its center in North Dakota. There are two major formations of hydrocarbon production in the Williston Basin – the Late Devonian-Early Mississippian age Bakken Formation, and the underlying Devonian Three Forks Formation. The 2013 USGS assessed an undiscovered, technically recoverable resource estimate of the Bakken Formation at 3.65 billion bbl and the Three Forks at 3.73 billion bbl (Gaswirth et al. 2014). The study area is located in the McKenzie County, ND, on ConocoPhillips leased acreage, adjacent to the Nesson Anticline which is considered the sweet spot of the basin (**Fig. 1**.).

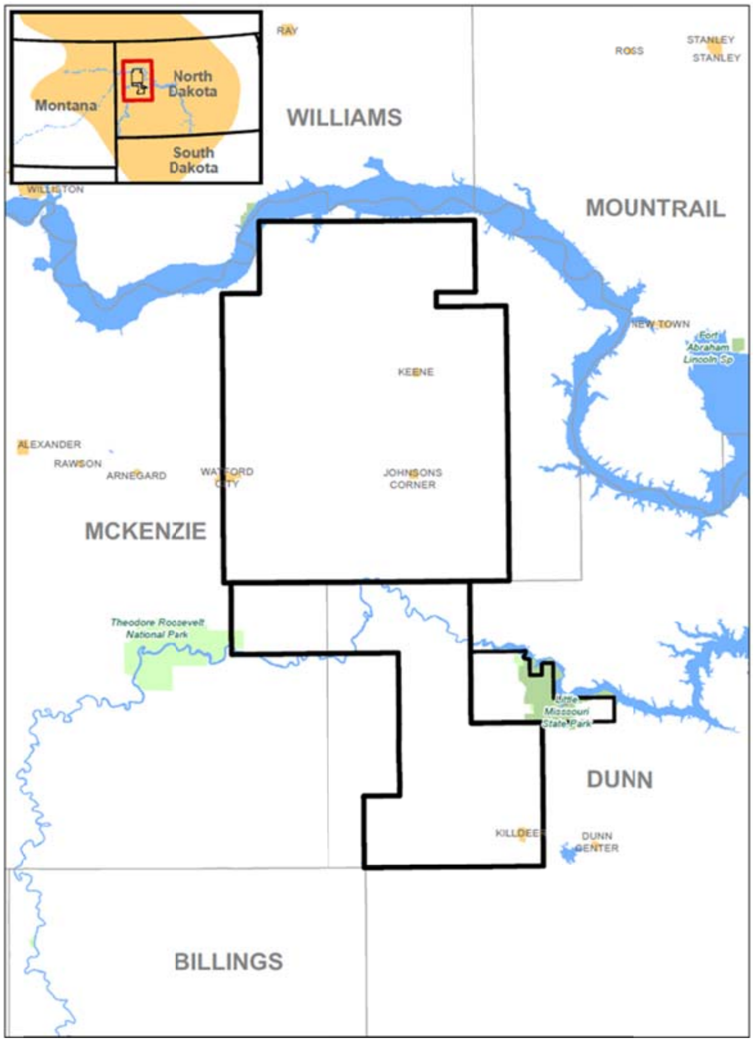


Figure 1: Location of study area in black line – McKenzie County in the west of North Dakota and center of the Williston Basin (relative location in the top left inset image).

<u>Program Set-up</u>

For this study, end member oil samples were extracted from the interior pieces of a fresh preserved core from a pilot-hole well (Well C). A number of oil extracts were selected from the stratigraphic zones of interests. A full year produced oil, gas and water sampling program starting from flowback was launched on two wells from the Middle Bakken and Upper Three Forks (**Fig. 2 and 3**) that were in close proximity to the cored well. Samples were taken at twelve hour intervals during flowback and spaced out at two month intervals for the remainder of the program.

Four producing end-members were identified from core extracts and used in this study, namely, the Upper and Lower Bakken Shale (UBS/LBS), Middle Bakken (MB), Upper Three Forks (UTF), and the Middle Three Forks (MTF). The Upper and Lower Bakken Shales were indistinguishable in terms of their chemical composition, and they are considered a single end member. Other surrounding intervals were considered only marginally productive and were not included in this study.

Whole oil gas-chromatography (GC), API gravity, and gas-chromatography mass-spectrometry (GCMS) measurements were conducted on the saturates and aromatics of the core extracts and produced oils. All the data processing and calculations were conducted using a proprietary software package.

For this study, the GCMS on the aromatic fractions carried the most effective information on the vertical zone differentiation; these data were used for the quantitative production allocation reported in this paper.

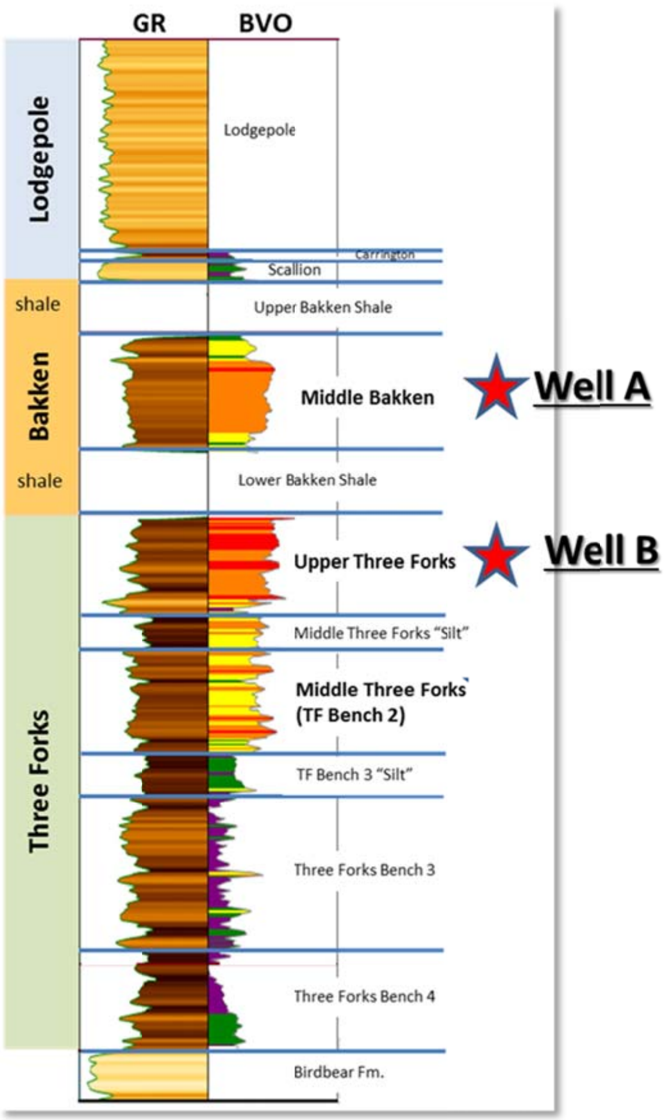


Figure 2: Well log from the Pilot-hole Well C with associated core gamma ray (GR) and bulk volume oil (BVO) with illustration showing the location of the two horizontal TLG wells (Well A and Well B).

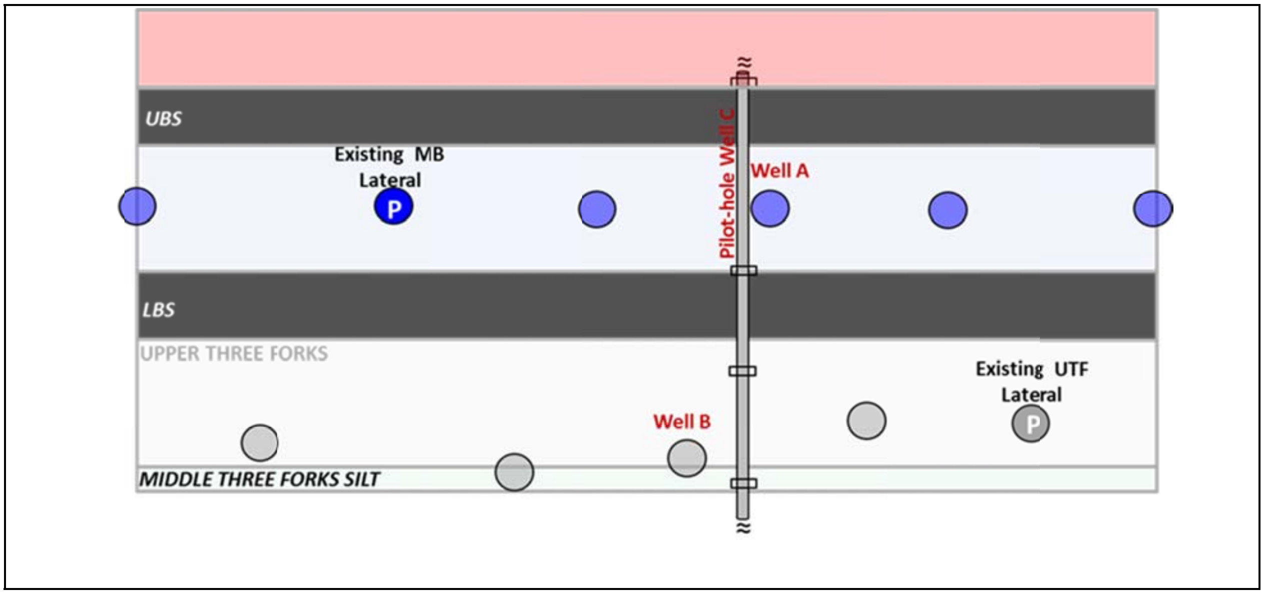


Figure 3: Cross-section showing locations of the Pilot-hole Well C where the core was taken, and the two TLG wells (Well A and Well B). Not to scale

Key Results

In the current case study, oil and water geochemistry were found to be most leveraging for performing quantitative production allocation by interval (**Fig. 4**). Biomarker signatures collected from oil samples clearly separated MB-landed producer and TF-landed producers (**Fig. 6**). The ability to set end members for gas composition with only drilling mudgas composition for comparison was insufficient for quantitative calculation, although trends clearly existed that were qualitatively consistent with both the oil and water chemistry. Similarly, water chemistry could be used to qualitatively assist with the allocation, but a quantitative allocation using only water chemistry was challenged due to a limited number of available isotopes (**Fig. 5**).

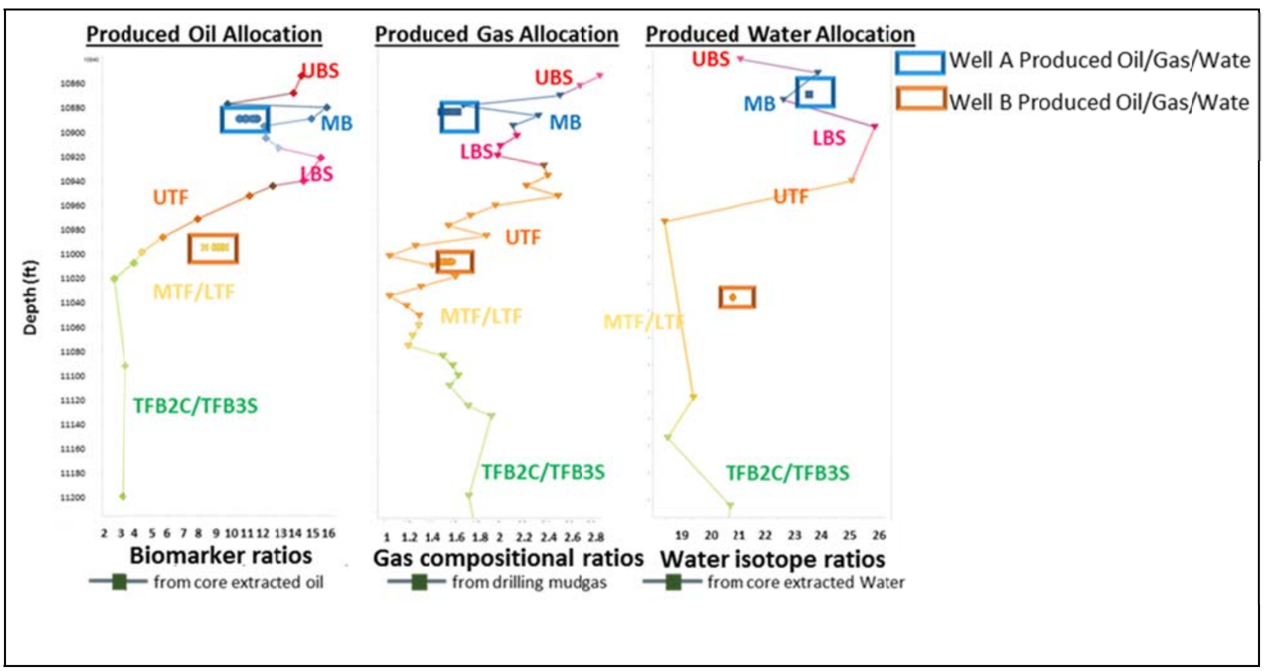


Figure 4: Cross-plot of chemical signatures vs. depth in end members vs. produced fluid of oil, gas, and water respectively.

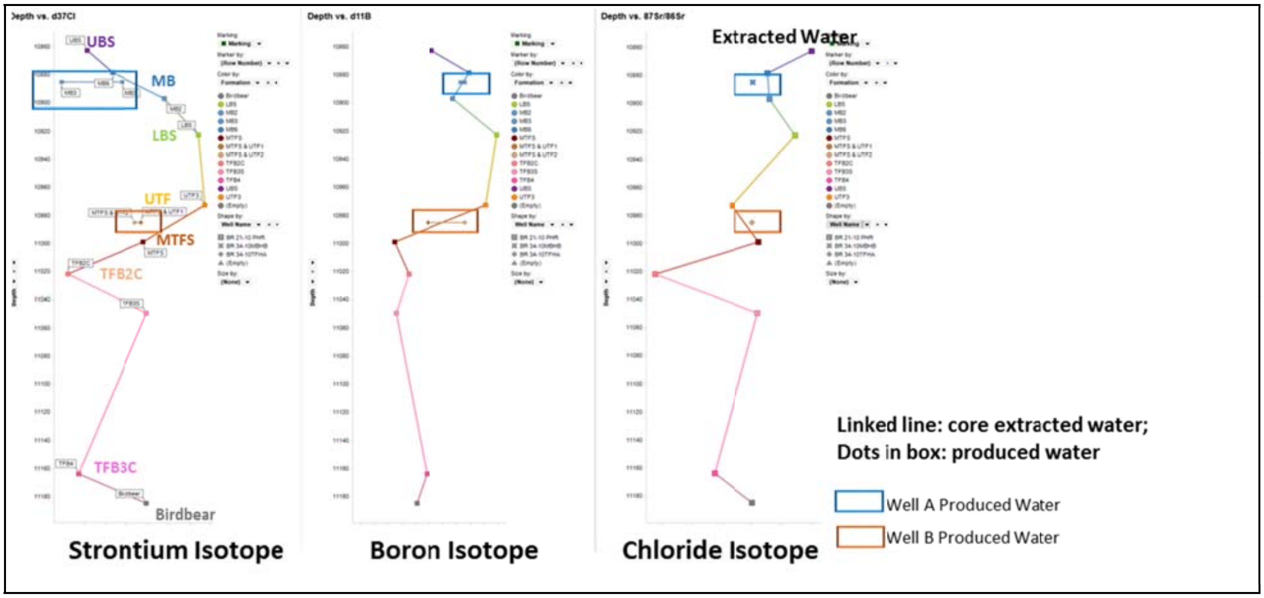


Figure 5: Cross-plot of chemical signatures vs. depth in end-member water compared to produced water.

A strong cross contribution is shown between the MB and TF wells which appears to continue over the length of one year (**Fig. 6**). Over the first year of production, Well A, which was landed in the MB, is estimated to have produced ~55% from the MB interval and ~40% from the TF. Well B, which was landed in the TF, is estimated to have produced ~62% from the UTF and ~32% from the MB. Shale contribution remained under ~5% in the first year in both wells in this pilot. Despite large volumes of in-place oil in the UBS and LBS, their contribution was found to be minimal and close to our error bar of ~±5% on the methodology. The shale contribution did appear to be slightly higher at initial flow back time relative to long term production (**Fig. 7 and Table 1**). The low amount of shale contribution is consistent with the matrix permeability data, which indicate the UBS and LBS permeabilities are an order of magnitude lower than those of the MB and TF reservoir intervals. The TLG supported the idea that fractures through the LBS are remaining propped open to flow for both MB and UTF producers up to 1 yr, and this was also supported by the down-hole pressure gauge data. Similar findings of strong cross communication between MB and TF wells, and minimal shale contribution were made in multiple other TLG pilots in the area. Additionally, TLG data from other pilots indicated that MTF-landed producers can be differentiated from UTF-landed producers (not shown in this paper). Therefore, the UTF-landed producer Well B appeared to demonstrate limited downward frac growth based on the absence of MTF biomarker signatures in the Well B produced oil (**Fig. 6**).

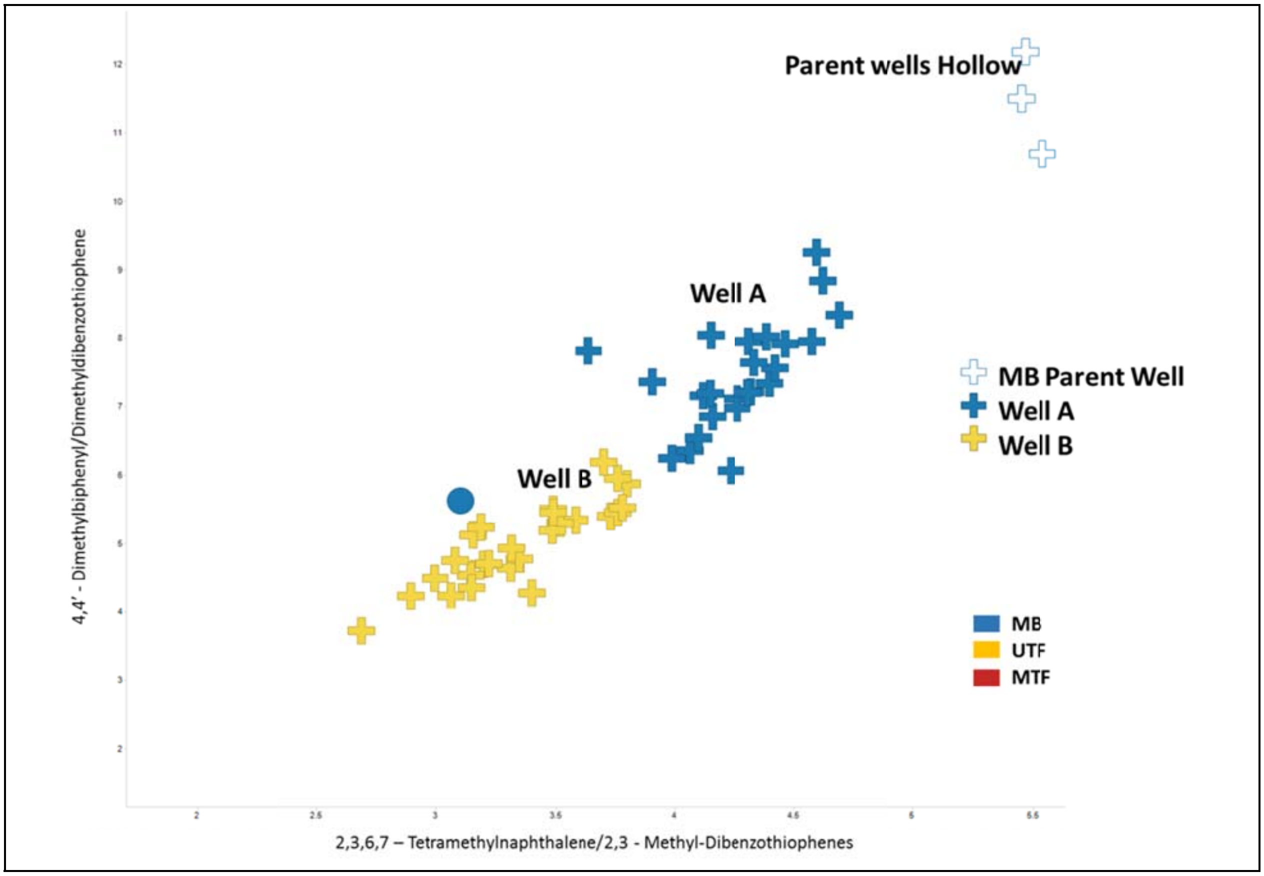


Figure 6: Separation between MB and TF intervals using two biomarker ratios in produced oil samples from Well A and B. Note that shale contribution is minimal to the wells shown and is therefore not shown in this plot.

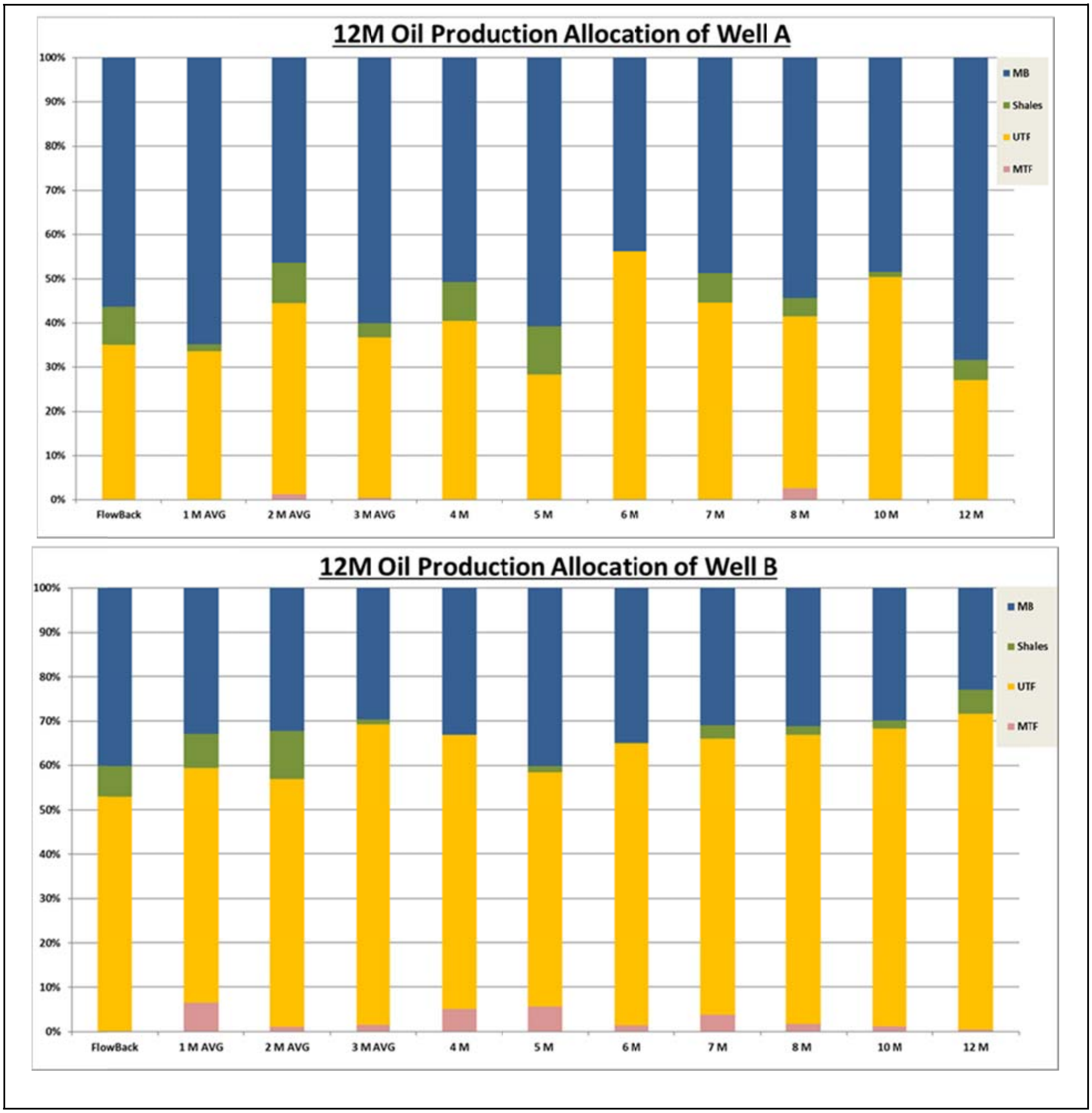


Figure 7: 12-month production allocation results of the produced oil from Well A (MB well) and B (TF well).

12M Oil Production Allocation of Well A

| | Flow-back | 0-6M Avg. | 7-12M Avg. | Full Year Avg. |
|---|---|---|---|---|
| UBS/LBS | 9% | 6% | 4% | 5% |
| MB | 56% | 54% | 55% | 55% |
| UTF | 35% | 40% | 40% | 40% |
| MTF | | | 1% | |

12M Oil Production Allocation of Well B

| | Flow-back | 0-6M Avg. | 7-12M Avg. | Full Year Avg. |
|---|---|---|---|---|
| UBS/LBS | 7% | 4% | 3% | 3% |
| MB | 40% | 34% | 29% | 32% |
| UTF | 53% | 59% | 66% | 62% |
| MTF | | 4% | 2% | 3% |

Table 1: Quantitative allocation results of the produced oil from Well A (MB well) and B (TF well) in 12-month period.

## Data Integration

The studied area is a data-rich, multi-well pilot where we also collected microseismic data (**Fig. 8**), chemical-tracer, as well as well interference tests. The DRV interpreted from TLG results is more constrained than the SRV revealed by the microseismic data. For Well A, the fracture height reflected by the microseismic data indicates the fractures reached up well beyond the UBS and down into the Middle and Lower TF, while TLG data indicates the DRV was largely constrained between UBS and UTF. For Well B, microseismic showed the fracture growth up into the Lodgepole and down to the lower part of the LTF, while TLG indicates DRV shows limited downward growth to MTF which is consistent with production allocation indications of limited MTF contribution to production.

The misapplication of the SRV concept discussed in Cipolla's paper (Cipolla et al. 2014) largely explains the differences observed in the current study between DRV (from TLG) and SRV (from microseismic). SRV calculation is based on the spatial distribution of events, proximity to neighboring events, and event density. The relationship between SRV and fracture geometry is not completely understood (Maxwell et al. 2011, Warpinski et al. 2012), and microseismic events do not reveal any information in terms of fracture conductivity and connectivity to the wellbore. The SRV is indicative of the fracture height, length, and location, but the amount of the stimulated rock contributing to oil/gas/water production also hinges on many other factors including matrix permeability and proppant location. In comparison, since TLG is based on the produced fluid itself, the DRV calculated from the TLG data is a direct representation of the drainage area resulting from the combined effects of SRV, fracture and reservoir conductivity, proppant placement, etc. Therefore, it is understandable that the SRV is typically largely than the DRV as is observed in our case.

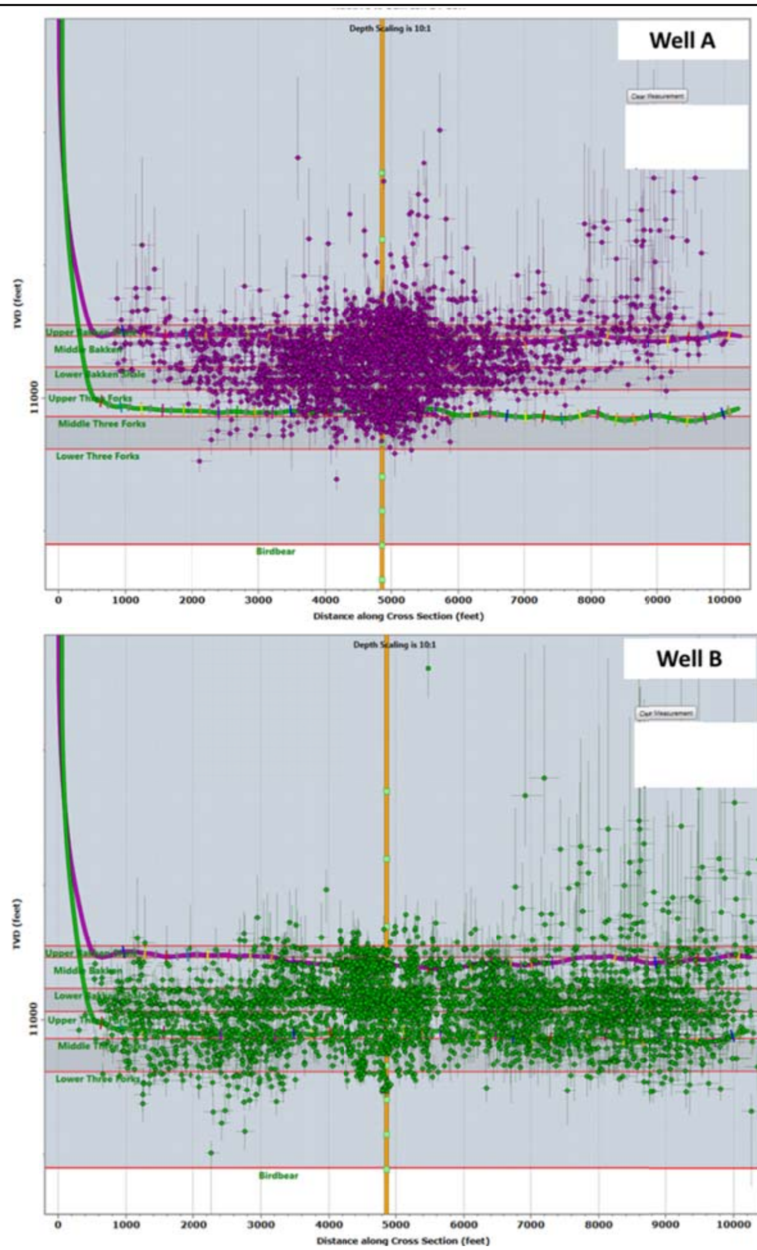


Figure 8: Micro-seismic events observed in Well A (MB) and B (UTF). Location of vertical monitor well shown.

By nature, any diagnostic tools only provide insights on what has happened but cannot predict what will happen. Therefore, in order to predict the impact of key completion and development variables (landing zone, well spacing, job size, slick water vs. gel completion, etc.) to planning the field development, all information needs to be captured in a reservoir model. The TLG results are integrated with rock fracture modeling, rock and fluid properties and production information to calibrate the reservoir model and eventually explore the economic impact of assorted well spacing and stacking arrangements. **Fig. 9.** schematically demonstrates the integrated workflow for incorporation of TLG learnings in the decision-making process for Bakken field development.

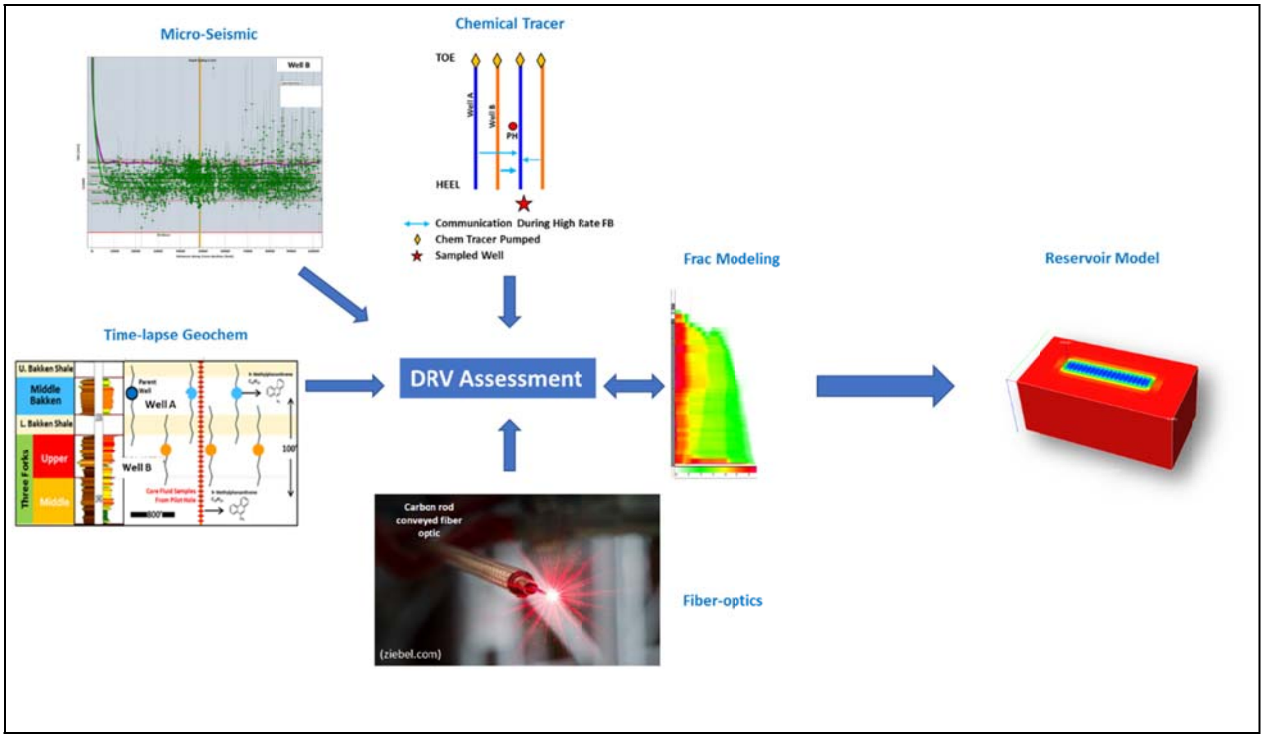


Figure 9: The integrated workflow for DRV calibration using subsurface information.

## Discussion

### *Limitations and Further Applications*

A major limitation to the geochemistry based methodology is the requirement that distinct end members exist in the drainage area; this is not always the case, even with proximal high quality core. The ability to extrapolate the end members from core extracted oil is limited also to a certain distance from the core.

TLG data can also be utilized in a qualitative manner. This opens the potential for less expensive analytical tools (e.g. GC vs. GCMS) and sometimes easier data processing. Qualitative methods can take advantage of the use of gasoline range compounds from GC (see an example in **Fig. 10**) with high reproducibility which are not present in core extracts. Many of the geochemical signals that are recorded and confirmed to carry valid zone separation information from core extracts can be confirmed in the produced oils, but due to differences in compound concentrations by zone and fractionation during production, are not useful for quantification (**Fig. 11**).

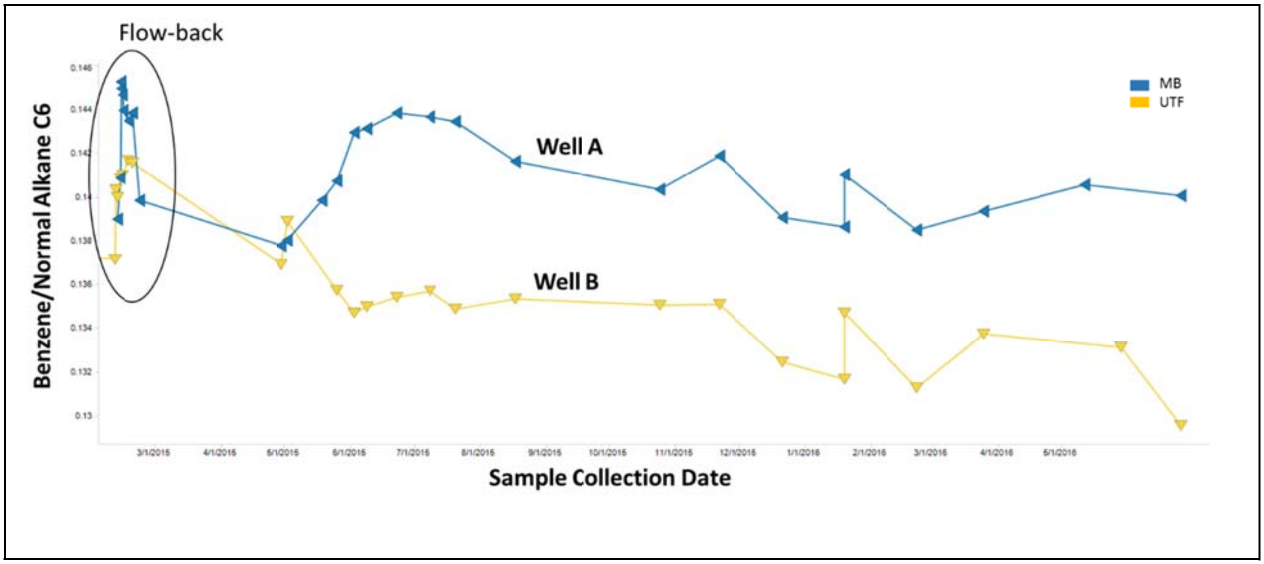


Figure 10: An example of good separation between MB and TF wells using compounds in the gasoline range from GC.

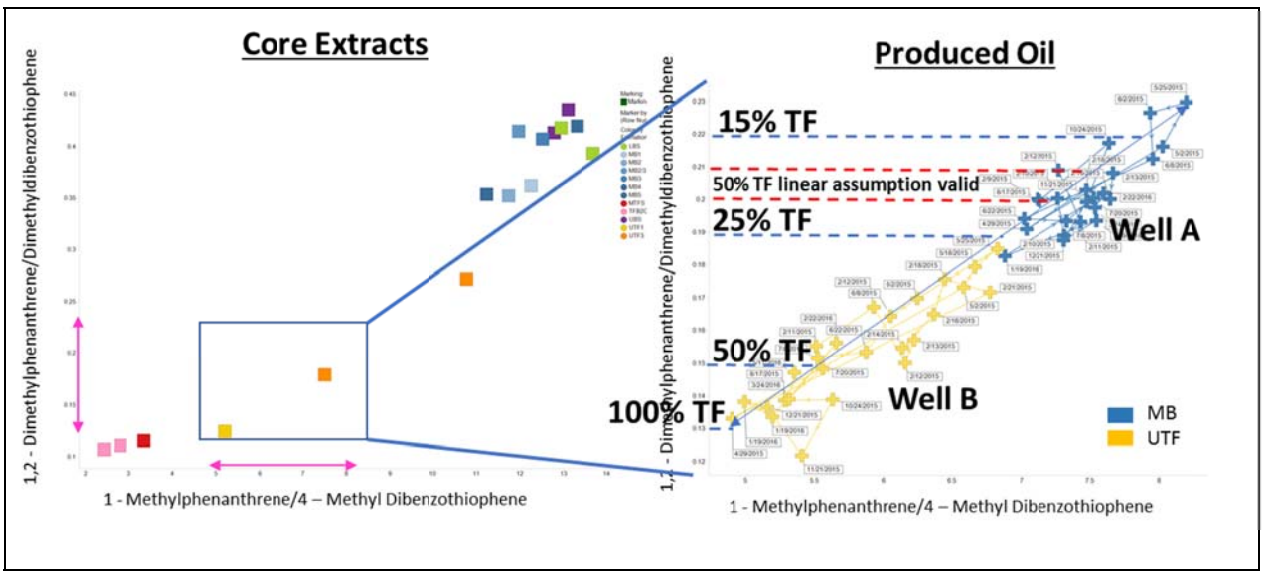


Figure 11: An example of biomarker ratio shift from core extracts (left) to production oils (right), despite the range shift, they still carry valid qualitative information on the intervals. The TF mixing line for produced oil shown is for linear assumption where compounds in ratios are in nearly identical concentration and for non-linear using concentrations as observed; however, the unknown end member is subjectively set.

An example of qualitative TLG monitoring is shown in Fig. 12. From quantitative TLG analysis we know that MB and TF laterals drain across the Lower Bakken Shale We do not know the exact end members on the plot, but a few items can be deduced from the data. The parent wells (wells drilled as the first wells in the area to hold lease, i.e., drilled into undeleted reservoir) on production for 3-5 years prior to the in-fill wells have different responses. The MB parent well stays considerably away from MB infill, sampled before and after infill drilling and stimulation.

From the prior discussion, we know that the MB TLG averages 55% MB (Table 1). We can infer then that the MB contribution is predominant in the parent MB well. Interestingly, the TF parent well sampled after stimulation groups similarly with with the infill well. This suggests that the TF parent well continues to drain a mixed zone focused upward.

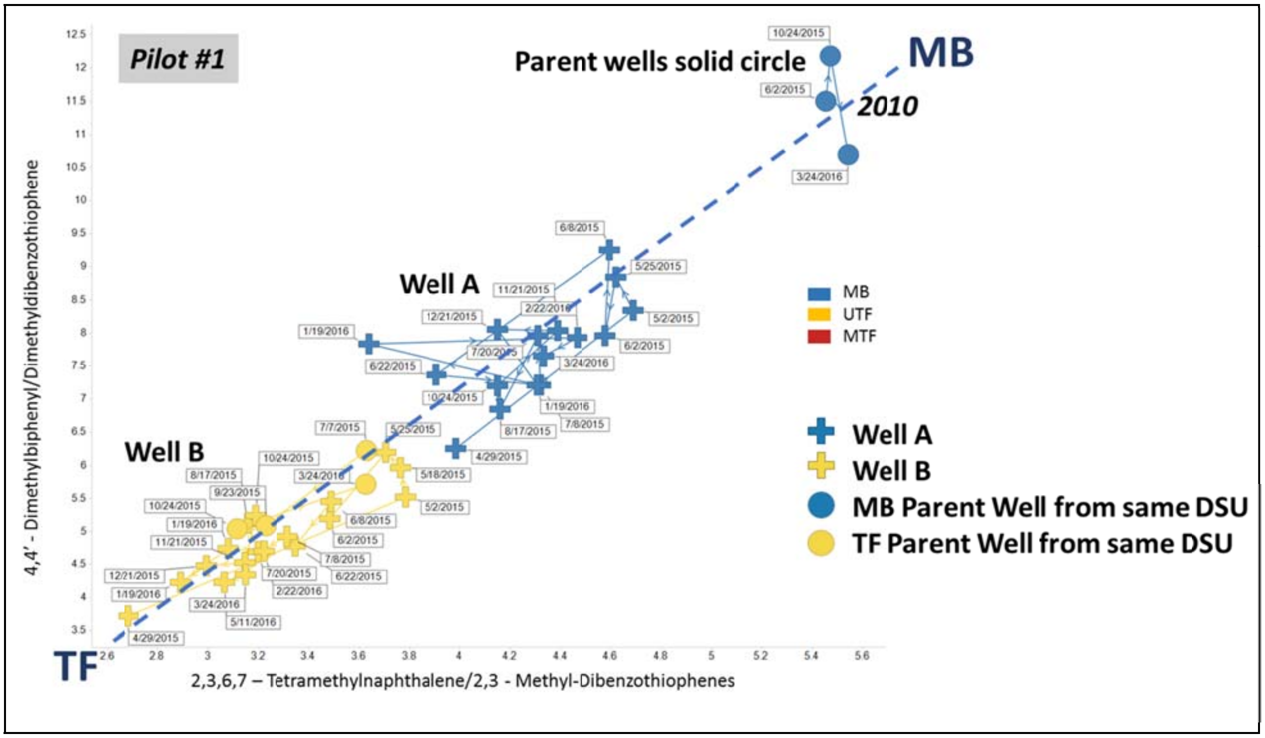


Figure 12: Example of cross-plot of two diagnostic biomarker ratios that separate time series production for Well A and B and the two MB and TF parent wells. The MB parent well clearly separates from MB infill well (Well A) production while the TF parent well does not separate from its infill well (Well B). Note: MB parent well was completed in 2010 and the TF parent well was completed in 2013. Both Well A and B were completed in 2015. The data also indicate how older parent well drainage can be affected upon infill drilling.

*Application of TLG to other North American Unconventional Assets*

The TLG workflow and toolkit has been developed and continuously improved at ConocoPhillips for applications in unconventional plays since its first application in 2010 in the Barnett Shale gas play (Freeman et al. 2012). It has been successfully used in multiple liquid rich shale and tight hybrid plays across North America including Barnett, Niobrara, Eagle Ford (Jweda et al. 2017), Bakken, and the Permian Basin, as well as in multiple areas and formations of the West Canada Sedimentary Basin.

**Conclusions**

We presented a novel approach using time-lapse geochemical fingerprinting in oil, gas and water to characterize the DRV and dynamic production contribution from each interval through time in an unconventional hybrid reservoir. The key challenge of end-member characterization in shales and other tight rocks was overcome by extracting oil from the core of corresponding intervals and statistically separating out the zone-specific information. As a new addition to the diagnostic toolkit for unconventional plays, TLG provides a cost-effective, non-invasive, and flexible (with different sampling frequency, different combination between oil, gas and water, etc.) option with a unique chemistry-based feature.

This method has been successfully applied in Bakken play where the key conclusions from this TLG application are as follows: 1) significant cross-formation well communication (30 ~ 60%) was observed between stacked MB and

UTF wells; 2) shale contribution remains low (within 5~10%) in both MB and UTF wells; 3) MTF contribution remains low in the UTF-completed well. These pieces of information show value in various field development decisions including well spacing and stacking, infill drilling, and well completion designs.

**Acknowledgement**

We thank ConocoPhillips for permission to publish.  We acknowledge the programing support of David Bunch, Pipat Likanapaisal, and business unit support of Kayla Robinson, Aya El Attar, Matt Freeman, Ryan Phelps, Ann Drewry, Stephanie Erickson and Mitch New, for their assistance in the execution of this work. Weatherford and TetraTech are thanked for geochemical analysis work.

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