PS Pitfalls in Geological Mapping Within Unconventional Plays: A Case Study From the Three Forks Play in the Williston Basin*

Riley Brinkerhoff[1], Sarah Edwards[1], and Mark Millard[1]

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Abstract

Historically geologists have identified oil and gas prospects by mapping a conventional reservoir's water saturation (Sw), porosity (Phi) and thickness (H). These three measurements proved to be reliable predictors of reservoir productivity and could be integrated into a single calculation, the SoPhiH map. In conventional plays, a SoPhiH map can be used to quickly identify sweet spots. In tight oil plays, however, SoPHiH maps can mislead operators as to where the highest yielding reservoirs are due to the complex nature of unconventional reservoirs and the necessity to hydraulically stimulate the rock. One example is the first bench of the upper Three Forks in the Williston Basin, where core helium porosities and water saturations, when averaged over the entire reservoir interval, are relatively consistent over large areas. Since averaged Sw and Phi do not change significantly, areas with the greatest reservoir thickness calculate the highest SoPhiH. Operators have targeted areas with the thickest first bench but unfortunately, the zones with the highest calculated SoPhiH ultimately proved to have some of the poorest production. This is due in part to the variability of different lithologies within the Three Forks and associated effective porosity and permeability. Careful identification and separation of lithologies and facies within the first bench and measurements of reservoir properties such as capillary pressure and brittleness within each facies are critical in identifying potential sweet spots. Unconventional production is impacted by many factors that are not included in SoPhiH maps and these maps should be used with care.

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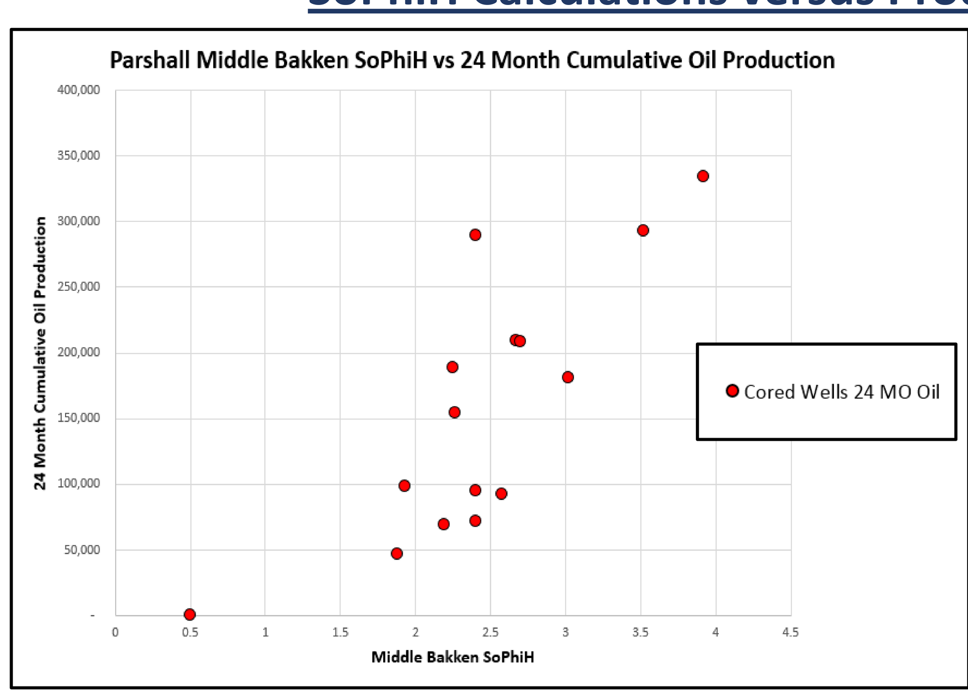
SoPhiH: The Good, the Bad, and the Ugly

Riley Brinkerhoff, Sarah Edwards & Mark Millard

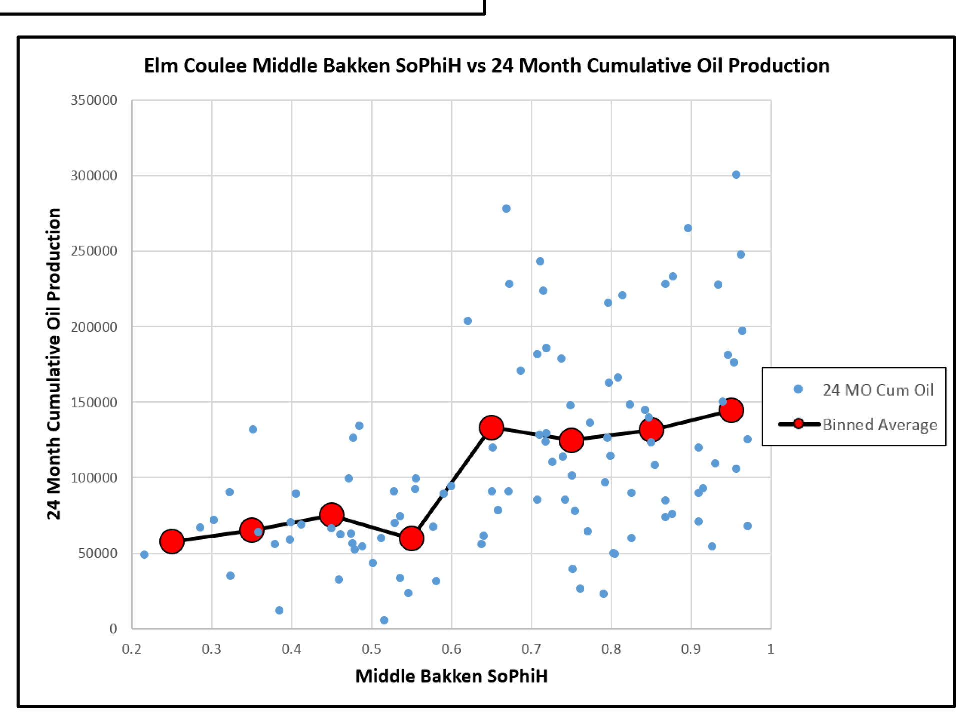
Abstract

Historically, geologists have identified oil and gas prospects by mapping a conventional reservoir's water saturation (Sw), porosity (Phi) and thickness (H). These three measurements proved to be reliable predictors of reservoir productivity and could be integrated into a single calculation: SoPhiH. In conventional plays, a SoPhiH map can be used to quickly identify "sweet-spots," where greater oil in place generally correlated with higher yields. In tight oil plays, however, SoPhiH maps can mislead operators as to where the highest yielding reservoirs are present due to the complex nature of unconventional reservoirs and the necessity to hydraulically stimulate the rock. One example is the first bench of the upper Three Forks Formation in the Williston Basin, where core helium porosities and water saturations, when averaged over the entire reservoir interval, are relatively consistent over large areas. Since averaged Sw and Phi do not change significantly, areas with the greatest reservoir thickness calculate the highest SoPhiH. Operators have targeted areas with the thickest first bench of the Three Forks formation, however, in the northern half of the Williston Basin, the zones with the highest calculated SoPhiH ultimately prove to have some of the poorest production. This is due in part to the variability of different lithologies within the Three Forks Formation and associated effective porosity and permeability. Careful identification and separation of lithologies and facies within the first bench and measurements of reservoir properties, such as capillary pressure and brittleness within each facies, are critical in identifying potential "sweet-spots." Unconventional production is impacted by many factors that are not included in simple SoPhiH maps, thereby limiting the effectiveness of SoPhiH maps. Simple and effective mapping methods include careful identification of effective reservoir rocks through capillary pressure measurements for effective porosity, UV photography, and careful gas show analysis. Since ineffective reservoir lithologies absorb frac energy and limit connectivity to better rock, ratios of effective and non-effective reservoirs often are helpful maps.

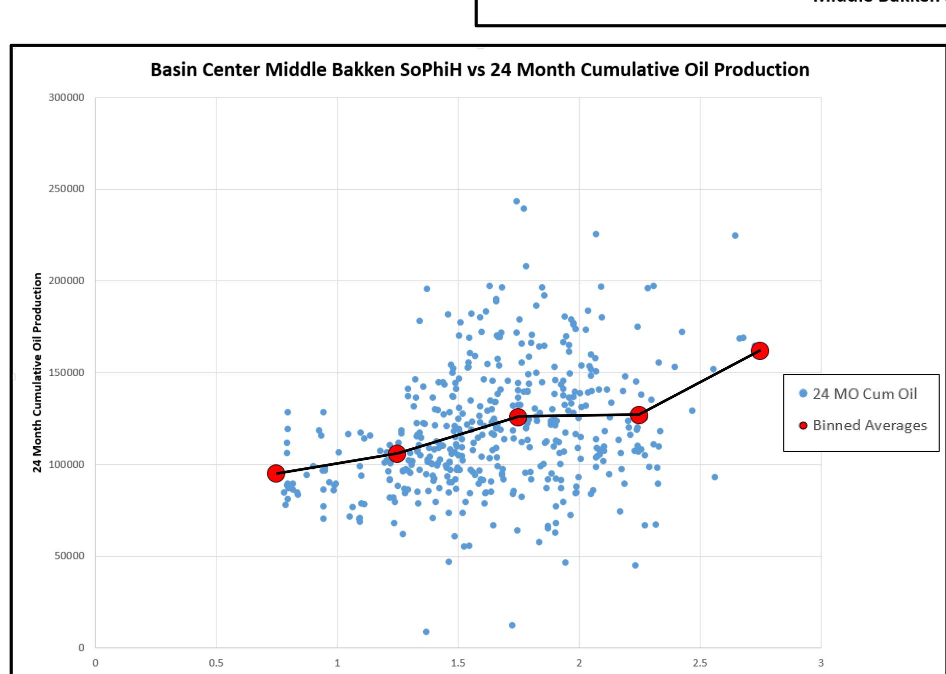
SoPhiH Calculations versus Production



These cored wells with excellent geologic control in Parshall Field show a dramatic increase in production with higher SoPhiH



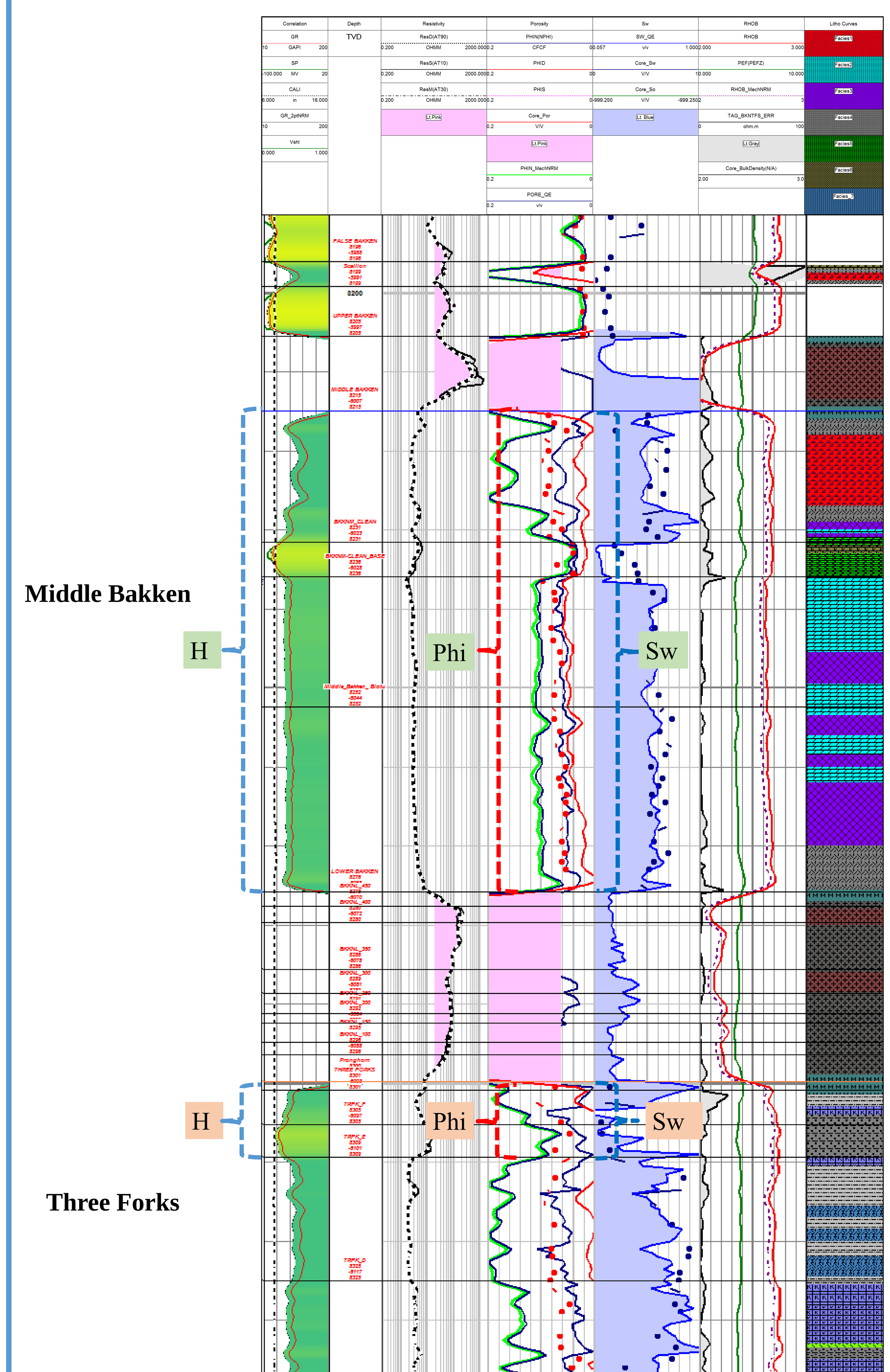
Elm Coulee Field wells have a wide variety of lateral lengths, completion types and production practices, but SoPhiH still correlates with better production



The overpressured center of the Williston Basin in northern Mckenzie County shows a correlation between production and SoPhiH despite the noise of various engineering practices and operators.

SoPhiH Is a Great Mapping Tool

Calculating SoPhiH from log or core data can be a quick way to map the potential productivity of a reservoir. The calculation contains three parameters that can easily be tied to the volume of hydrocarbons in place; So-the oil saturation of the reservoir, Phi-the porosity of the reservoir, and H-reservoir height.



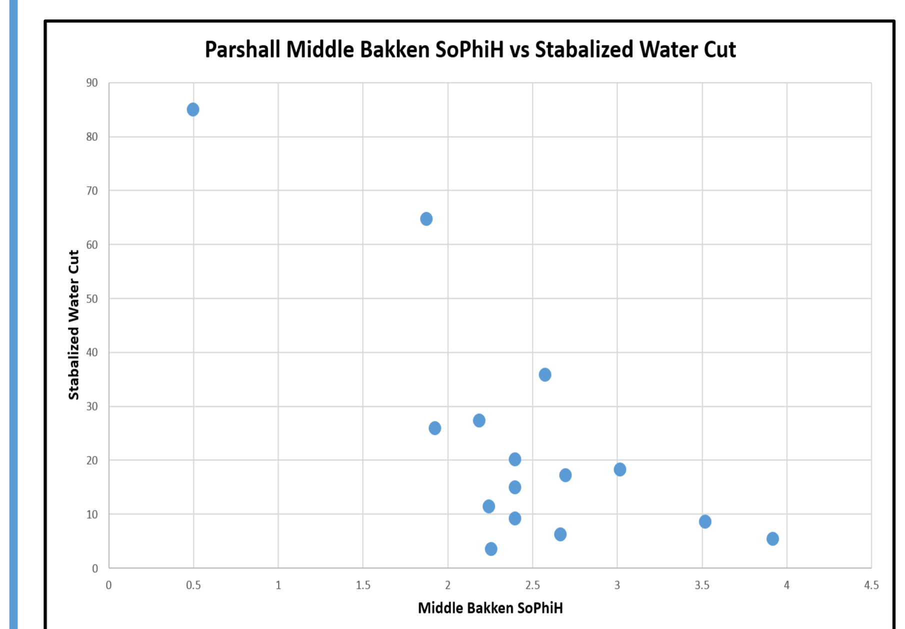
An interpreter will typically take the following steps to calculate SoPhiH (see example below):

1. **Calibrate all the well logs within an area of interest to available core data.**
2. **Calculate Sw and Phi curves that have the best match to the data, adjusting the inputs based on the lithologies for each zone.**
3. **Divide the section into producing units, in this case, the Middle Bakken and Three Forks.**
4. **Calculate SoPhiH at foot or half-foot intervals and then sum the result over the identified producing unit.**

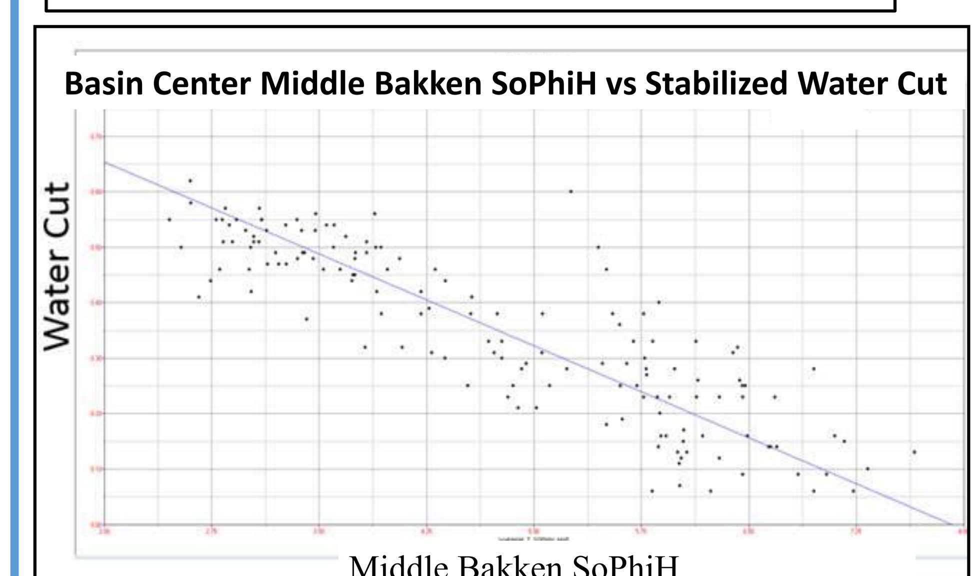
Middle Bakken Gross Interval 70'	Three Forks Gross Interval 9'
Net Pay 65.5'	Net Pay 8.1'
Average Phi 5.2%	Average Phi 4.3%
Average Sw 51.6%	Average Sw 22.9%
SoPhiH 1.65	**SoPhiH 0.27**

SoPhiH Calculations versus Water Cuts

Often in the Bakken/Three Forks play, lower water cuts correlate to better oil production. At the very least, lower water cuts lead to lower LOE costs. In some fields, SoPhiH mapping ties with lower water cuts.

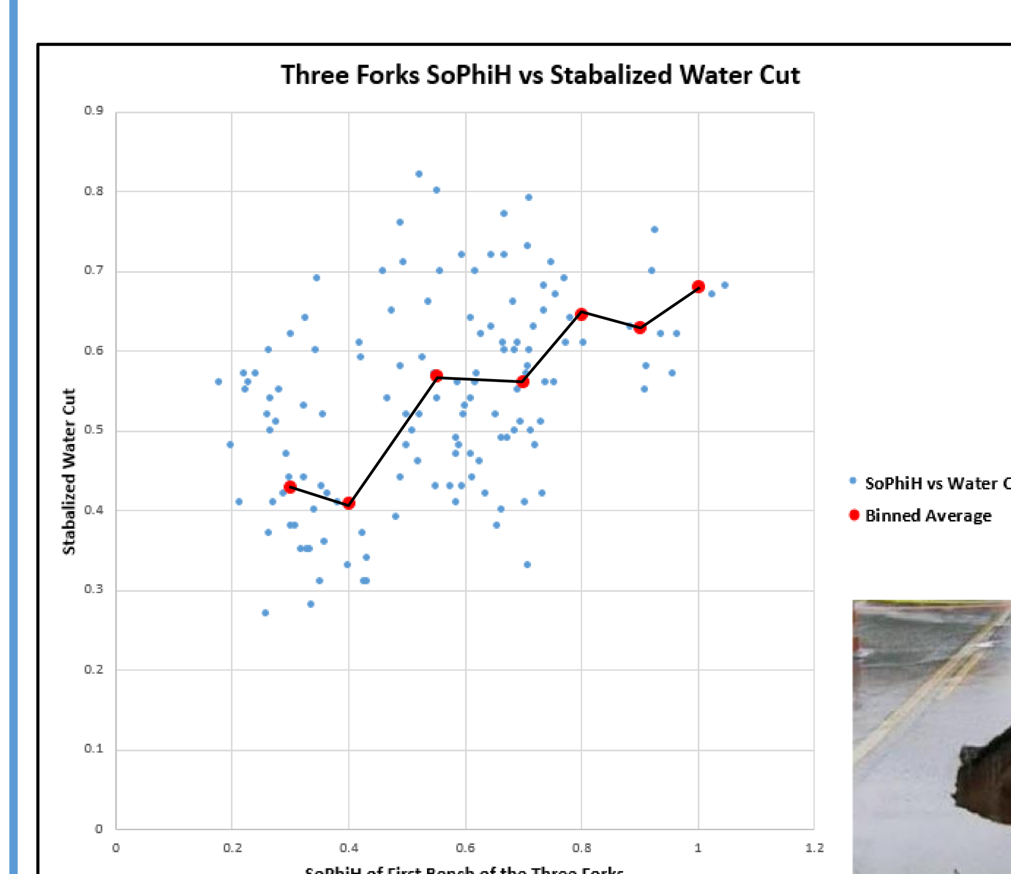


These cored wells with excellent geologic control in the Parshall Field have thicker, oil saturated Middle Bakken intervals that produced less water.



In the highly overpressured basin center, SoPhiH, which here is largely influenced by variations in Middle Bakken thickness, also correlates strongly with reduced water cut.

The relationship between produced hydrocarbon and water cuts in hybrid unconventional plays, such as the Bakken-Three Forks play, are often difficult to predict due to the highly variable lithologies within the stratigraphic section. The Three Forks Play is a good example of the influence of stratigraphic heterogeneity on well productivity. Intervals such as the clay-rich facies of the first bench of the Three Forks Fm., have poor reservoir characteristics such as poor effective porosity, low permeability, and high capillary pressures. As such, these intervals can exert an important control on production in this part of the Williston Basin.



In the northern half of the Williston Basin, the water cut of the Three Forks play have an positive correlation to SoPhiH. In this part of the basin, there may be other geologic controls at work.

Pitfalls in Geological Mapping Within Unconventional Plays: A Case Study From the Three Forks Play in the Williston Basin

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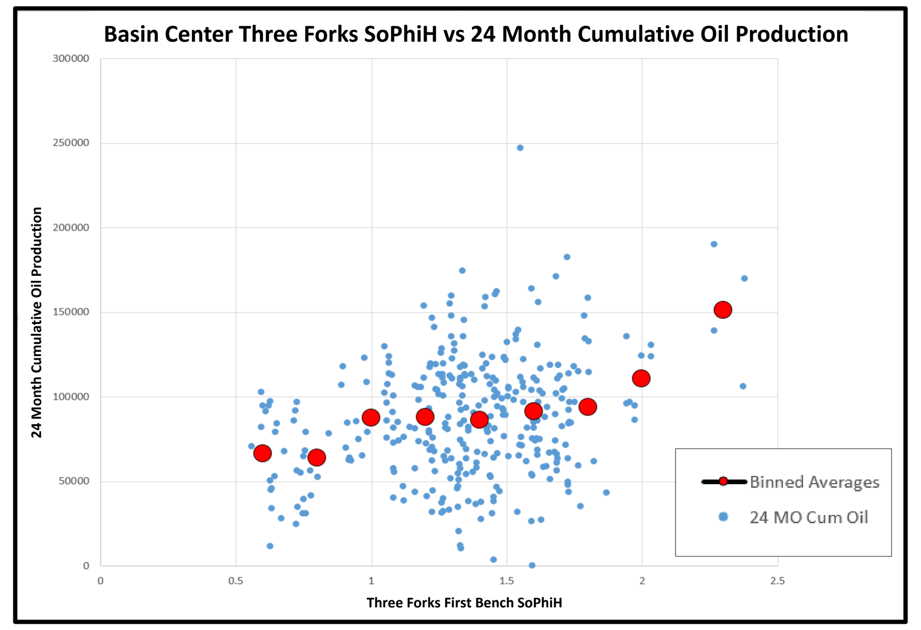
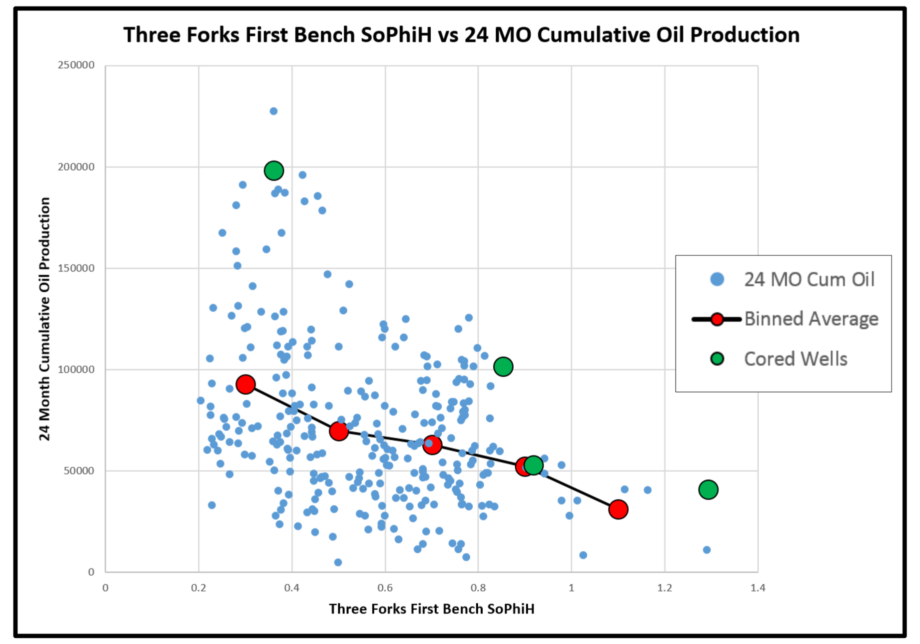
Problem

In many fields in the Bakken/Three Forks play, SoPhiH correlates positively with production even when engineering factors such as completion types and lateral placement are ignored. However, in the Three Forks play of the northern portion of the Williston Basin, SoPhiH often correlates inversely with production, with areas of low calculated SoPhiH greatly outperforming nearby areas of higher SoPhiH.



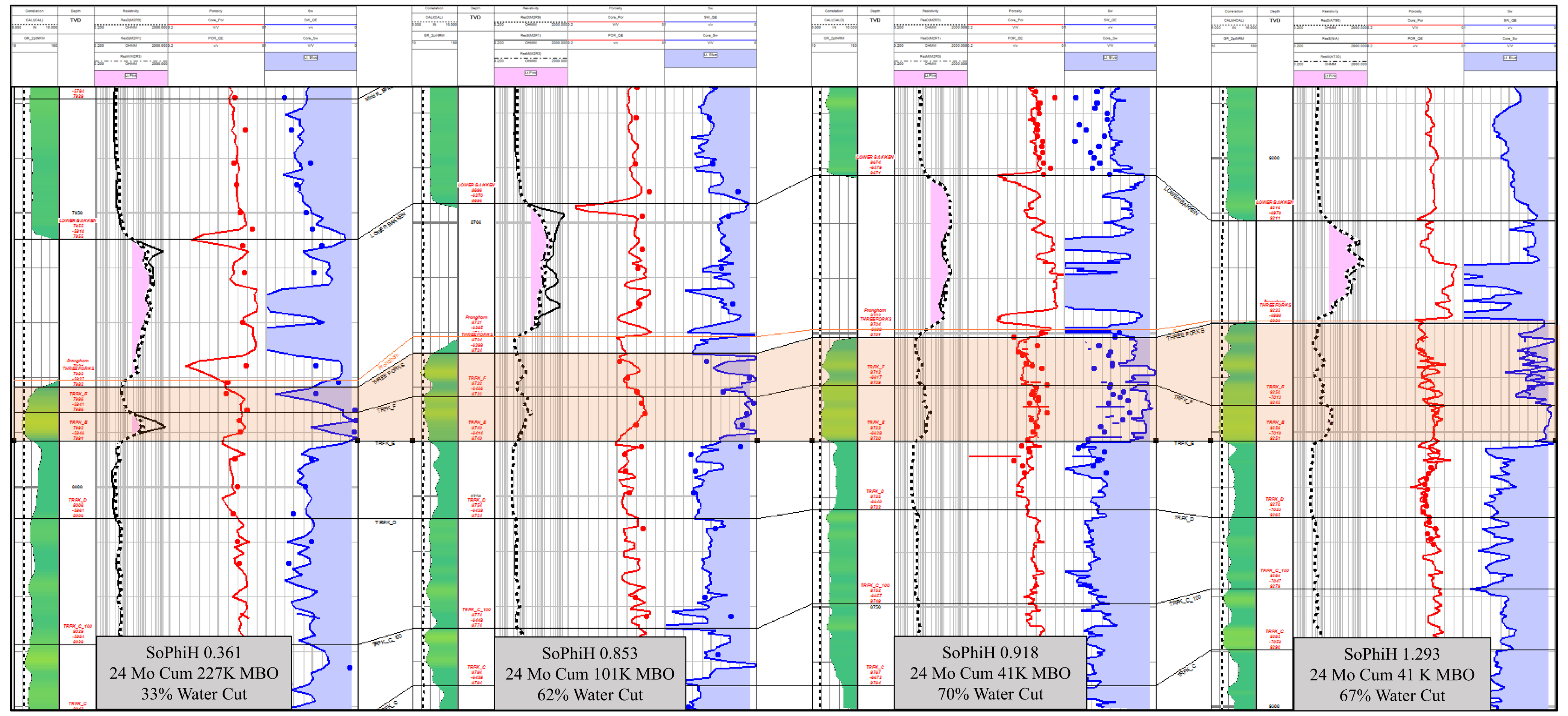
Key Questions

- Which intervals/lithologies contribute to production during the life of the well?
- Which tools/techniques are most effective in identifying and mapping effective reservoirs?
- How can we confirm the effectiveness of our current mapping strategy?
- As we better understand the factors that control productivity, how can we improve our lateral placement and stimulations?

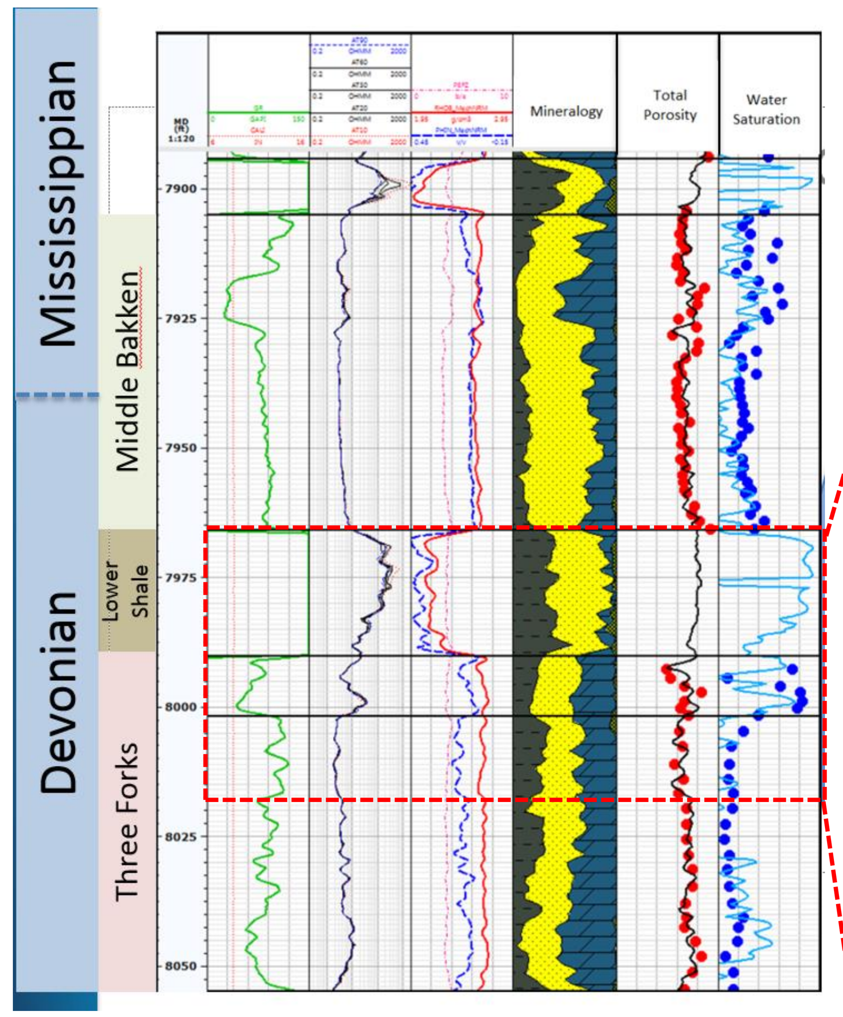


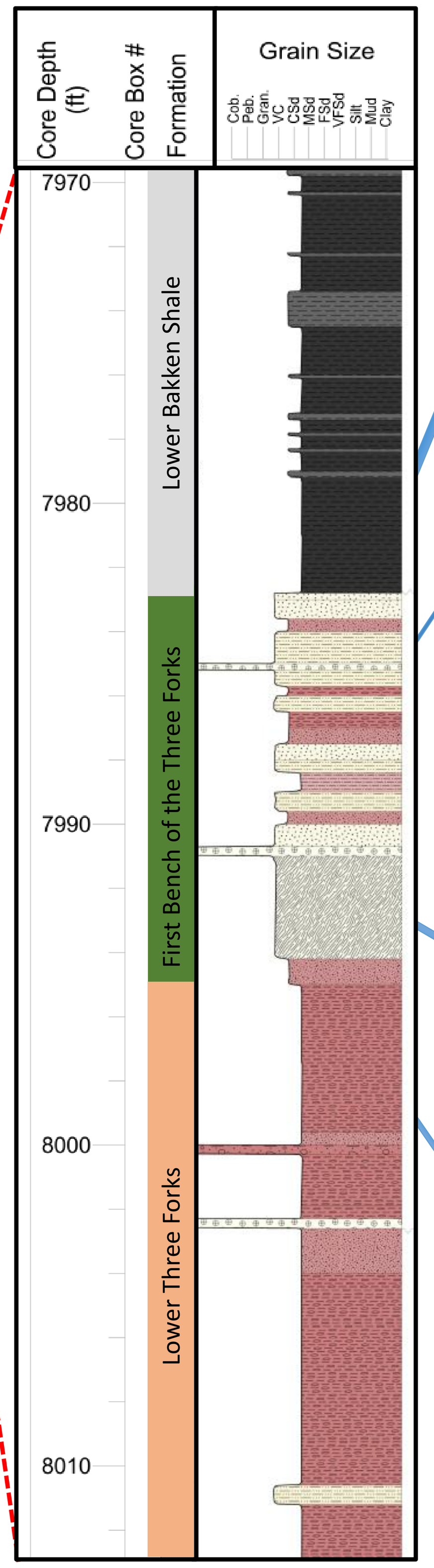
The two plots at the left illustrate the problem:

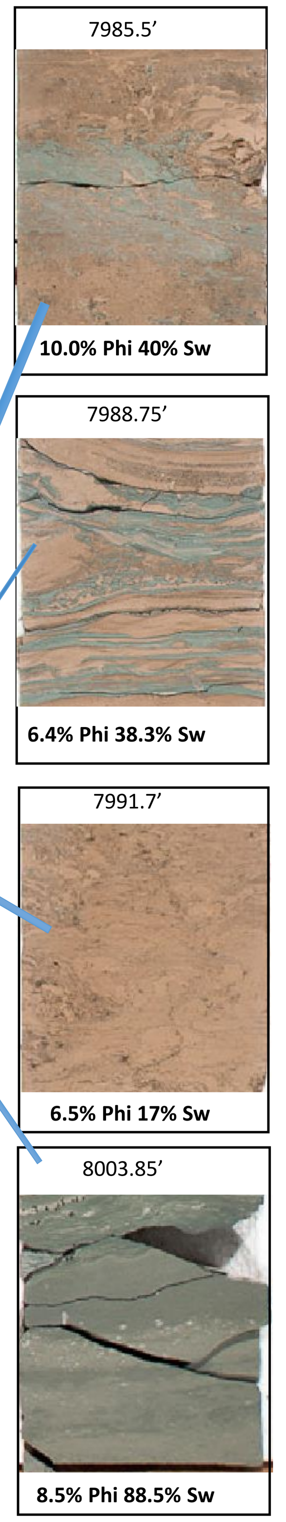
- In the overpressured basin center (upper plot), regardless of engineering concerns such as lateral placement or completion type, there is a positive correlation between higher SoPhiH and 24 month cumulative production.
- However, the in the northern portion of the basin (lower plot), there is a negative correlation between SoPhiH and 24 month cumulative production.
  - Wells with core (green dots), which should have the best data, show an even more pronounced negative trend



Danger of Averaging Rock Properties







Modified from Petty, 2014

Mixed Lithologies

Mixed green and brown breccia
- Average composition
  - 44% dolomite
  - 39% quartz-feldspar
  - 17% clay minerals

Mixed green and brown laminated
- Average composition
  - 35% dolomite
  - 39% quartz-feldspar
  - 22% clay minerals

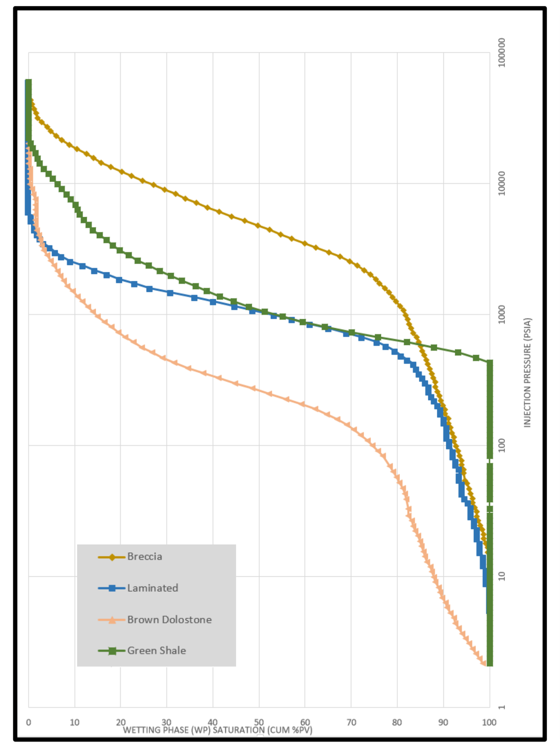
End Member Lithologies

Brown to tan, silty to sandy dolostone
- Average composition
  - 63% dolomite
  - 30% quartz-feldspar
  - 3% clay minerals

Green silty mudstone
- Average composition
  - 36% dolomite
  - 30% quartz-feldspar
  - 30% clay minerals
  - 2% pyrite

A common mistake in mapping the Three Forks is averaging the different rock properties of the first bench. In many simplified cross-sections, the entire first bench appears to have water saturations and porosities that have been averaged to a single value.
Interpreters tend to miss important differences in the reservoir quality of the various lithologies due to:
- Log resolution limits
- Biased core sampling

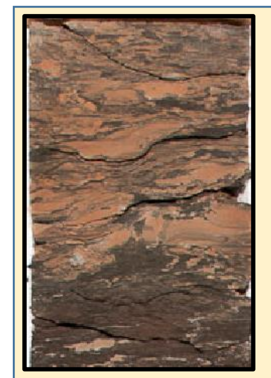
Unfortunately, Three Forks lithology is as complex as any other carbonate system, with large differences in reservoir quality and changes in lithology. Because individual beds are thin, wireline logs often don't capture the variability, and because geologists tend to sample the best rocks disproportionately, core datasets can also be misleading, therefore influencing your petrophysical model.

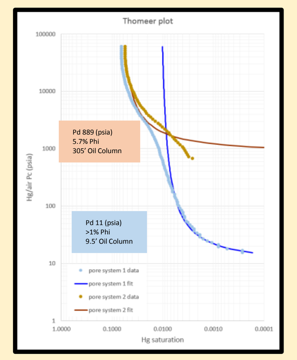


MICP plots are useful to show which intervals are likely to be effective reservoirs. Many rocks in unconventional plays have dual pore systems, they show what percentage of the measured porosity is effective. The brown dolostone, although it has the lowest measured porosity is by far the best reservoir since nearly all of it is effective. The mixed lithologies only have a small portion that is effective

This 17' thick Three Forks interval is typical for the first bench, with brown dolostone totaling 4' and green shale totaling 2'. The rest is mixed lithologies, either thinly-bedded or brecciated mudstones and dolostones.

What is Effective Porosity? How Can We Better Understand the Pore Systems?





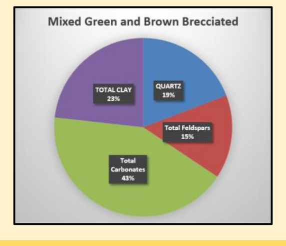
Mixed green and brown breccia

Describe lithology and character for lithofacies: Silty, sandy, argillaceous dolostone

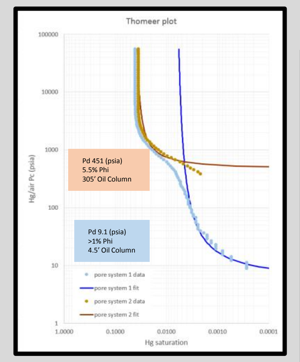
Thin section observations: Silty dolostone with intercrystalline porosity within a tight mudstone matrix

MICP: Capillary pressure data shows two pore systems, a small but permeable system in the dolostone with low entry pressure, and a much less permeable system in the mudstone

Summary and importance:
The breccia has little effective porosity available (>1%) and because what effective porosity it has is disconnected, little recovery should be expected



4.9% Phi
90.3% Sw
1st System 0.051 mD MICP Perm
2nd System 0.0006 mD MICP Perm



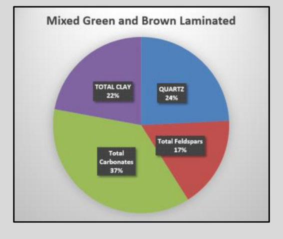
Mixed green and brown laminated

Describe lithology and character for lithofacies: Silty/sandy dolostone (35%), finely crystalline argillaceous dolostone (35%), and mudstone (30%)

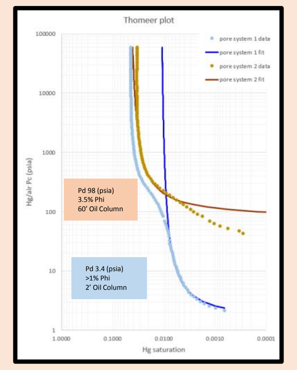
Thin section observations: Common, irregularly distributed, intercrystalline/intergranular pores, disturbed remnant laminations with abundant argillaceous clasts

MICP: Capillary pressure data shows at least two pore systems, a small but permeable system in the dolostone with low entry pressure, and a much less permeable system in the mudstone

Summary and importance:
The laminated lithology in this sample has little effective porosity available and because what effective porosity it has is disconnected, little recovery should be expected. However, where the volume of mudstone drops or pressure is higher, the facies has the potential to be an important contributor



6.4% Phi
38.3% Sw
1st System 0.043 mD MICP Perm
2nd System 0.0016 mD MICP Perm



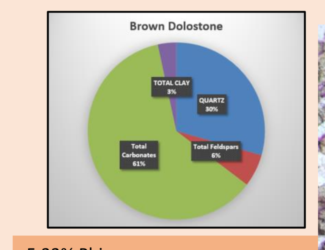
Brown to tan, silty to sandy dolostone

Describe lithology and character for lithofacies: Structureless (mottled) dolomitic siltstone and very fine-grained sandstone with dissolution fabric

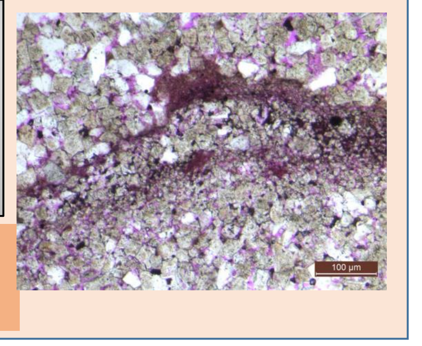
Thin section observations: Porosity within this sample is variable, but many areas have abundant intercrystalline and intergranular porosity. Sample contains little matrix clay on average

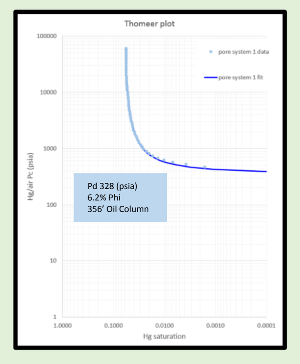
MICP: Capillary pressure data shows at least two pore systems, a small but very permeable system and a second system less permeable system, but both systems are effective

Summary and importance:
The brown dolostone has relatively low porosity but is almost all effective. This results in consistently low water saturations and high measured perm.



5.33% Phi
3.62% Sw
1st System 5.65 mD MICP Perm
2nd System 0.0303 mD MICP Perm





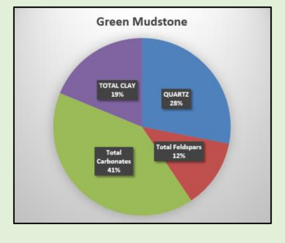
Green silty mudstone

Describe lithology and character for lithofacies: Brecciated (structureless) dolomitic siltstone and very fine-grained sandstone with large number of clay rich zones

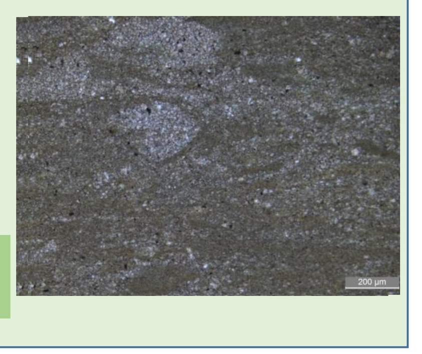
Thin section observations: Overall, this sample contains low porosity; porosity is most abundant along pyrite or lithoclast boundaries, and within or immediately adjacent to laterally discontinuous, horizontal to subhorizontal, open to clay-filled fractures

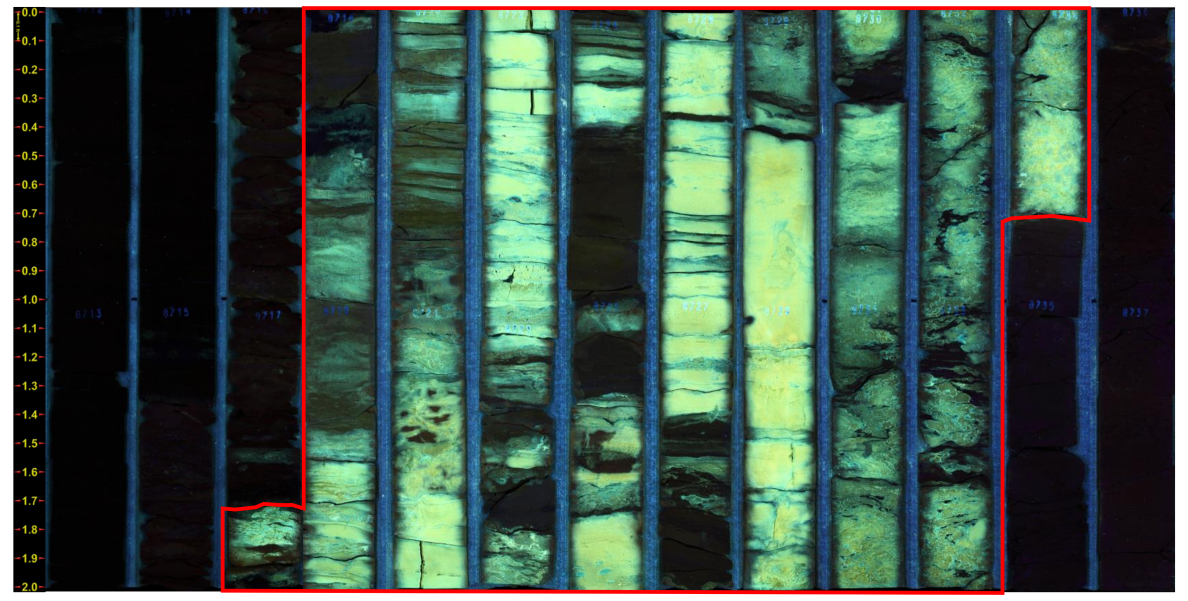
MICP: Capillary pressure data shows a single pore system that has high entry pressure.

Summary and importance:
The green mudstone has reasonable porosity and air perm, but as MICP data shows, it is not effective porosity and unlikely to be hydrocarbon charged

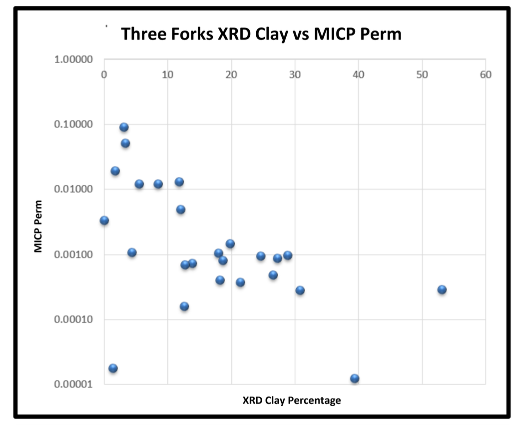


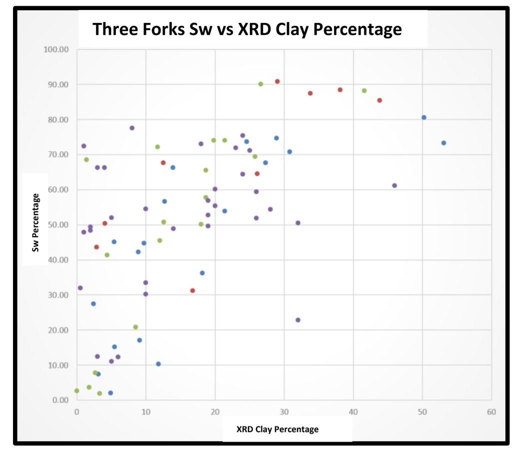
6.24% Phi
50.11% Sw
1st System 0.00394 mD MICP Perm





The same interval from the core on the left in UV showing that the brown dolostone has by far the highest free oil saturations, while the green mudstones have little or no oil. The mixed lithologies are somewhere in between.





In the Three Forks play, clay is a controlling factor on the potential reservoir effectiveness of each facies through its influence on pore throat apertures and related permeability values. The upper plot to the left (it might be helpful to label the plots A, B etc.) shows the rapid degradation of permeability with increasing clay. Ten percent more clay generally leads to an order of magnitude poorer permeability. The lower plot illustrates the greatly reduced charge in Three Forks rocks with higher clay values as measured by water saturation.

Mapping Workflows for Unconventional Rocks

Riley Brinkerhoff, Sarah Edwards & Mark Millard

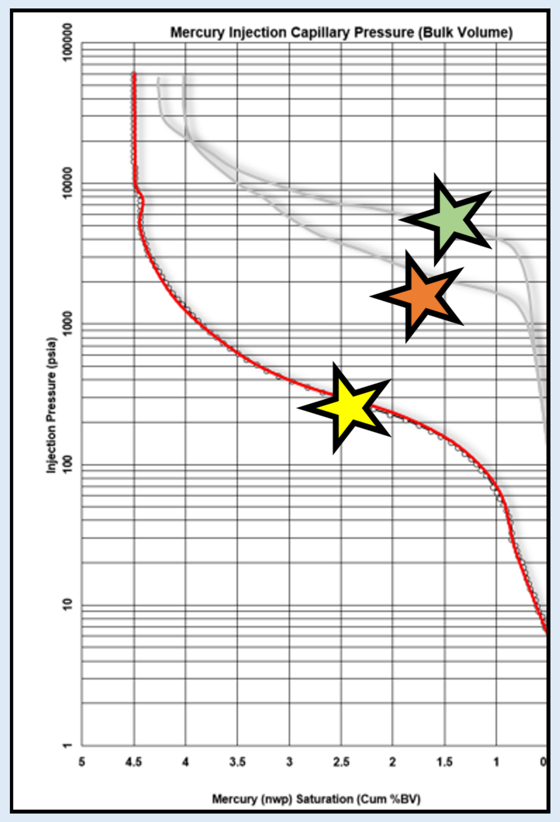
Better Mapping Methods

Identify the zones/lithologies that are most likely to contribute to production.

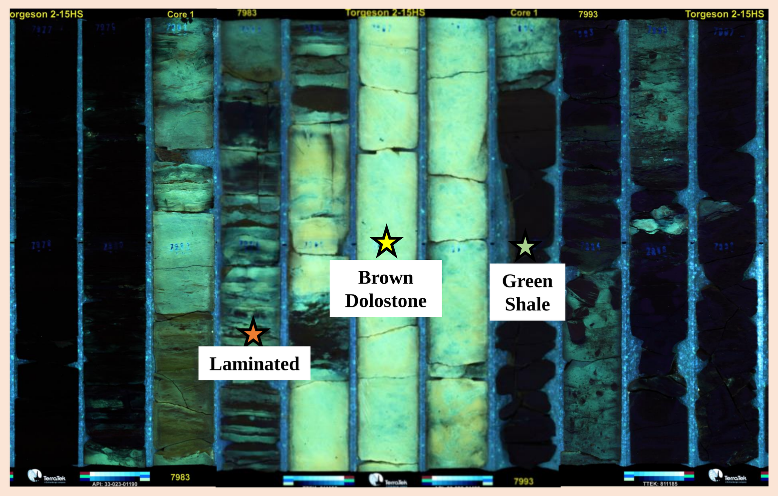
- What are the properties of potential flow units/reservoirs?
    - Standard core analysis
    - Lithology reports
- Which zones are likely to act as barrier/baffles?
    - Rocks that isolate potential flow units
    - High stress fracture barriers

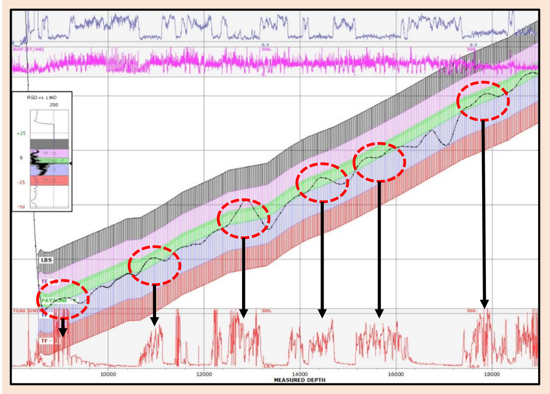
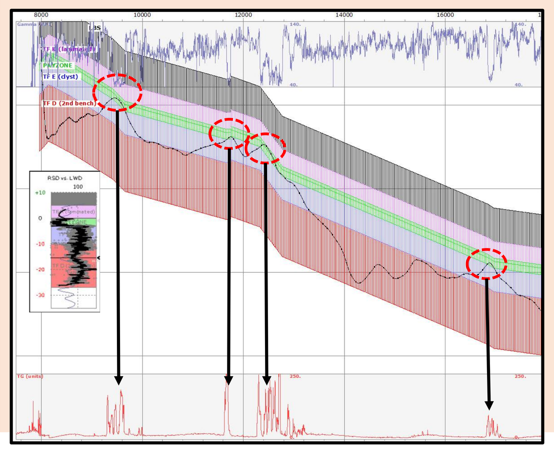

Collect and use capillary pressure data

- Use capillary pressure curves to quantify the effective porosity in each facies
    - Does the MICP porosity and air porosity correlate?
    - Is there enough storage in the effective porosity to make a prospect?
- Is there enough oil column height or overpressure to charge the identified facies?
    - If there is enough overpressure, do some of the non-reservoir facies become reservoirs?



Reality Check: Do the identified reservoirs fluoresce in UV photography? Do they have consistently strong gas shows?



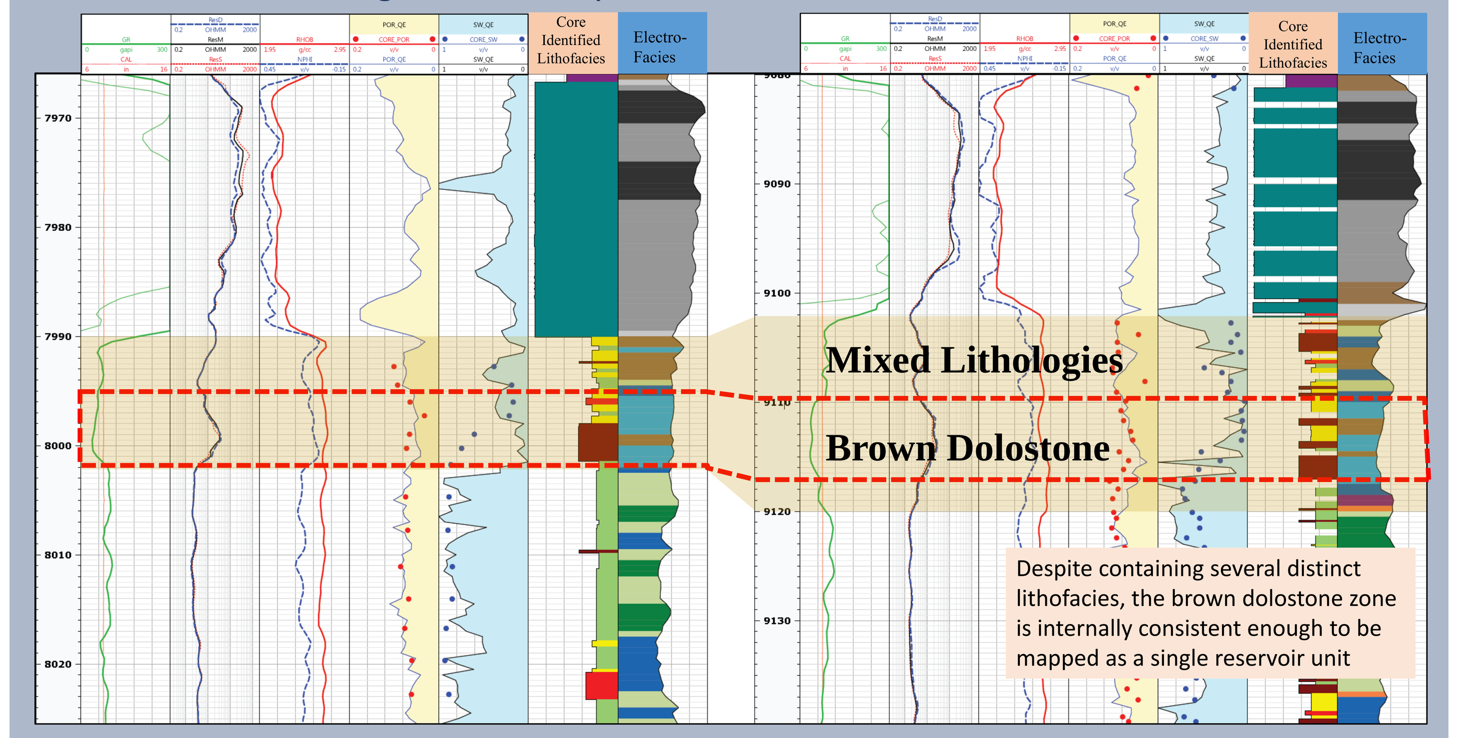



- Brightest fluorescing intervals typically indicate mobile hydrocarbons
    - Facies with dim fluorescence have some oil saturation, but are unlikely to be high quality reservoirs
- Do your best facies give the strongest gas shows?
    - Does the gas fall off when drilling through the poorer facies?

Upscale reservoir and baffle facies from core to log scale

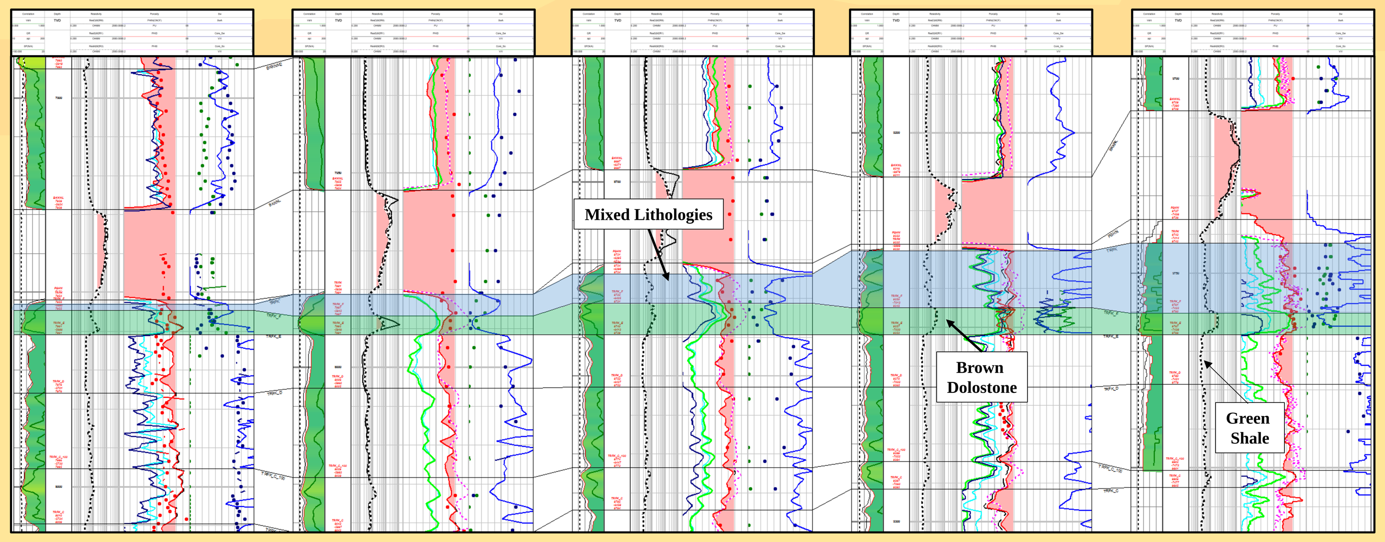
- Group similar core lithofacies
    - Rocks with similar effective porosity measurements and saturations should be grouped into a single log lithofacies
    - Often intervals with low effective porosity can be grouped using clay cutoffs
    - Caution! An interpreter could end up in the original SoPhiH problem if facies are grouped too broadly

- Using a normalized log dataset, identify log characteristics that are unique to the log lithofacies
    - Are the log lithofacies broad enough to be mappable?
    - Scale log resolution by the foot, not inch



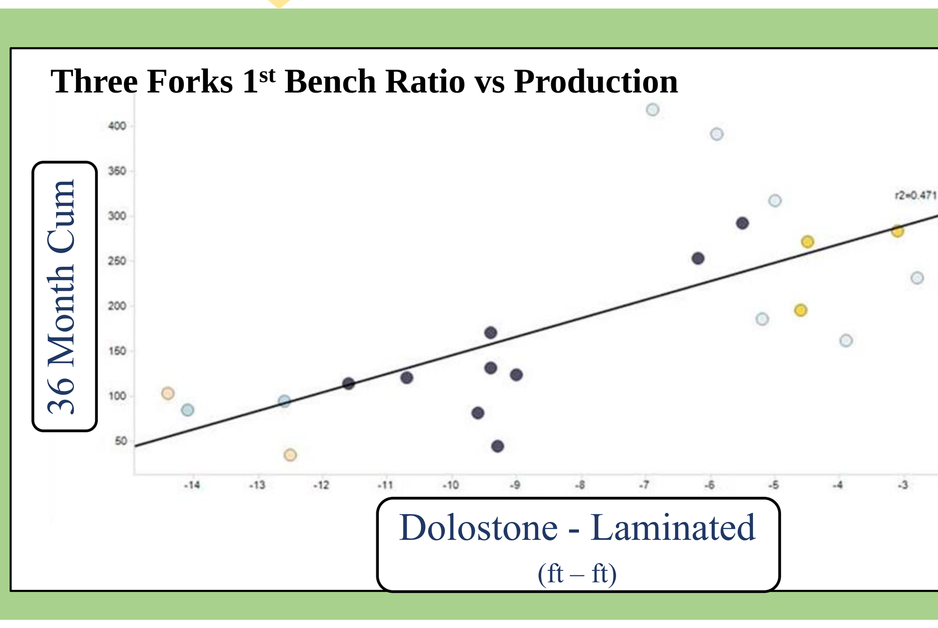
Do the log lithofacies make sense on a regional scale?

- As the facies are picked across miles and then tens of miles, does the grouping scheme still make sense?
    - As formations change laterally, are new lithofacies designations needs
    - Don't force rocks with different properties into a simplistic average

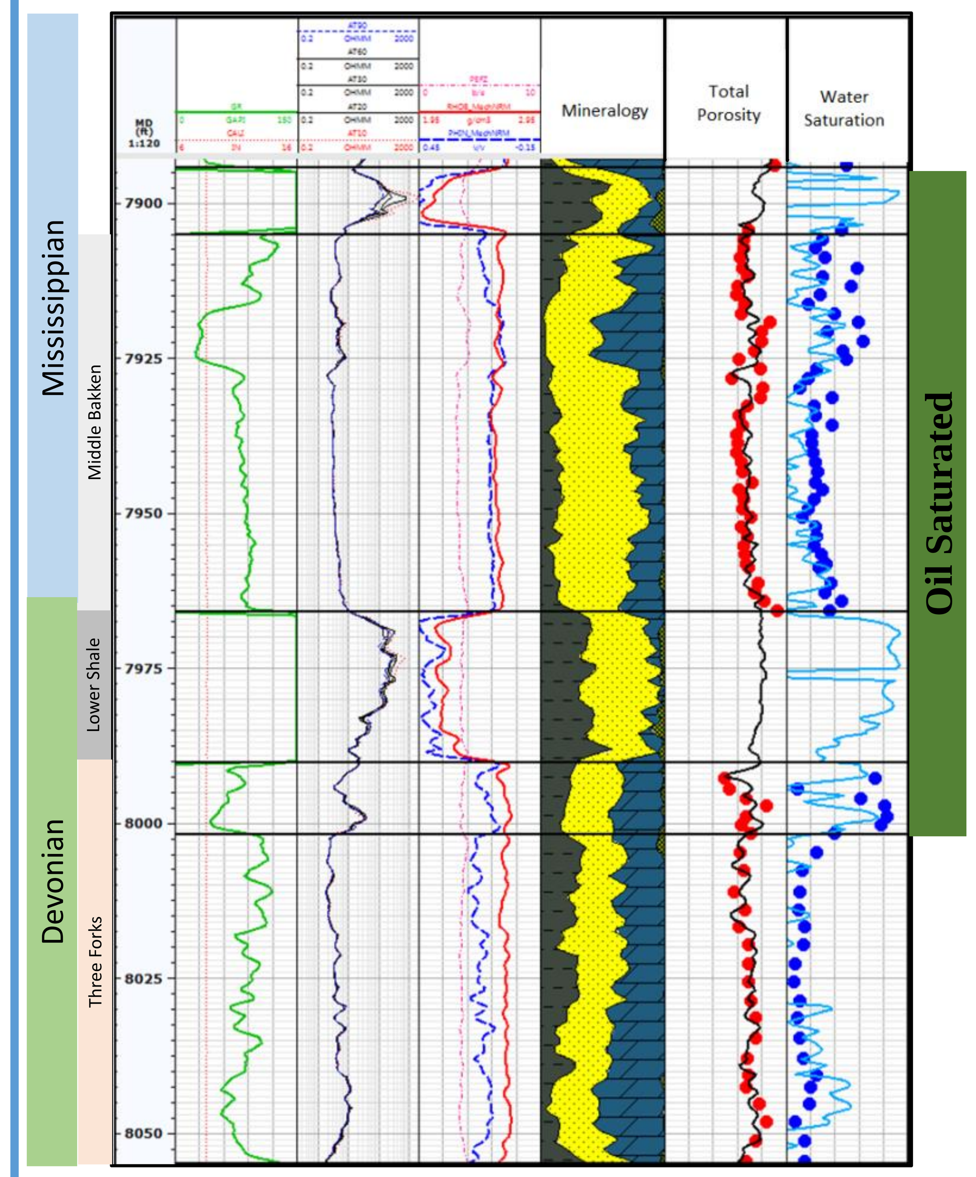


Do the resulting maps tie to production trends?

- Do the mapped log lithofacies correlate to production?
- Do ratios of good to poor lithofacies correlate better?



Be Aware of the Entire Petroleum System



- Local conditions such as tectonic fracturing, thin or brittle shale intervals, or highly permeable zones in the overlying Lower Bakken Shale and Middle Bakken could have significant impacts on Three Forks productivity.
- Do structural features or stratigraphic trends in adjacent sediments tie better to production trends than Three Forks stratigraphy?
- An important limitation in SoPhiH calculations in unconventional reservoirs is that we don't often know how much H is effective.

Summary

- While SoPhiH can be an effective mapping technique in individual fields within the Bakken/Three Forks play, it often gives very general results that do not help operators identify the factors controlling sweetspots.
- The production volumes of the Three Forks play in the northern half of the basin correlates inversely to SoPhiH using the same techniques that work in other portions of the basin, largely because the method averages lithologies of very different reservoir qualities.
- Increasing clay concentrations in the Three Forks Formation increases water saturations in both basin center and northern Williston Basin wells.
- Reservoir facies within the Three Forks Formation exhibit multiple pore systems due to lithologic heterogeneity however, the utilization of MICP allows for quantification of effective porosity and which pore systems are likely to be charged given the potential oil column of the area of interest.
- A better mapping method focuses first on identifying the effective porosity individual facies, grouping rocks of similar reservoir quality, and upscaling the groups to the log resolution scale.
- Resulting SoPhiH maps should be checked against production. If the correlation is poor, search for other factors in the oil-charged interval i.e. stratigraphic or structural features. Normalizing for the engineering inputs will make trends more clear.

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