Top Down Petroleum System Analysis: Exploiting Geospatial Patterns of Petroleum Phase and Properties*

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Abstract

The fluid-phase and bulk properties of petroleum fluids are controlled by the source rock organofacies, maturation, expulsion and pressure and temperature along migration pathway and in the traps. Together with the basin geometry and framework, these factors dictate the spatial distribution of oil and gas. “Top-down” petroleum systems analysis is the systematic interpretation of the distribution and properties of fluids, along with shows, seeps, dry holes, and any other relevant well data in the geological context. The aim is to discern patterns and place them in a petroleum system framework, thereby improving the quality of pre-drill prediction. The availability of “big-data”, especially the copious production data from unconventionals, and data analytics tools have enabled recognition of spatial patterns in fluid phase and properties: API gravity, GOR and the interpreted maturity of oils tend to be lower near the basin margins, while gas-condensates are most often found near the basin center, partly due to maturity variation but also to “migration lag” effects. In vertically drained systems, such as deltas and rift basins, lower maturity fluids are found in shallower/younger stratigraphic units. GOR and API gravity both increase with depth but can reverse locally in a leak through system. Phase separation also exerts a significant control on fluid phase and properties, especially in a mixed oil and gas petroleum system typical of deltaic settings. In many cases, GOR and CGR are controlled simply by reservoir pressure as the saturation pressure has already been reached along the migration pathway. At the same time, fluid phase found in the trap depends on whether the trap leaks or spills. High GOR (volatile) oils can only exist as a single phase in deep reservoirs due to their high saturation pressure. In unconventional settings, migration and/or pressure reduction may cause a moderate GOR oil to reach bubble point and then produce anomalously high GOR from a reservoir where the rocks have only low local thermal maturity. In this paper we show several examples of top-down petroleum systems analysis from around the world. As we often find fluids before we drill the actual source rock, this methodology can help constrain the petroleum system at an early stage and provide a reality check for basin models.

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Top Down Petroleum Systems Analysis:
Exploiting Geospatial Patterns of Petroleum Phase and Properties

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What Is Top Down Petroleum System Analysis?

Top down petroleum system analysis is the interpretation of fluids (accumulations, shows, seeps, and dry holes), their bulk properties (GOR/API/Sulfur …) and their distribution in the geological context and PT space to constrain the petroleum system to infer the location and properties of yet-to-find hydrocarbons:

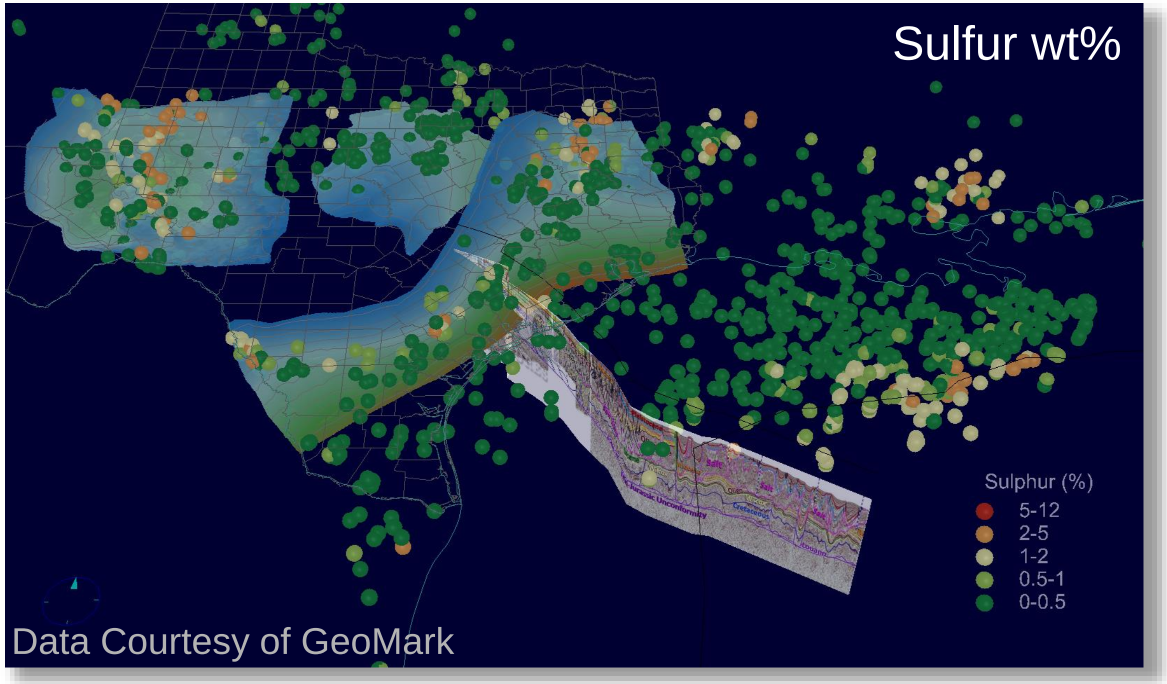
- ❑ What is the reason for this high API oil, or low API condensate?
- ❑ Where do we find oil, or a liquid rich pool in a gassy basin?
- ❑ For a known field, what is the expected fluid up dip, downdip, above and below in terms of fluid type, API and GOR?
- ❑ Can I predict oil vs gas, GOR without having source rock data?
- ❑ Many more …

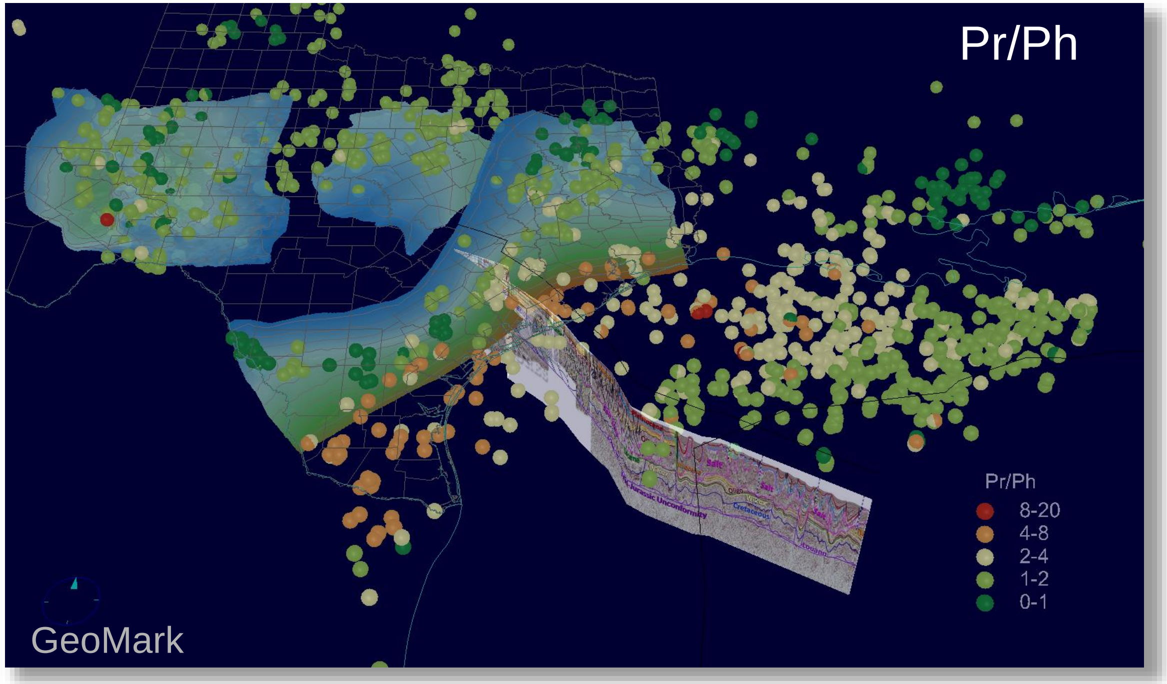
Why Is it Hard to Predict Fluid Type and Properties?

- Lab generated fluids do not look like those found in reservoirs: lower GOR, more aromatic, wetter gas, etc.
- Expulsion fractionation – expelled fluid is not the same as generated, kerogen preferentially adorbs heavier molecules
- Cumulative/Instantaneous: an accumulation typically traps a small fraction of what is expelled. The trapped fluid would be lighter if earlier charge has to be spilled, such as in a fill spill chain (Gussov, 1954)
- Migration fractionation – spilled, or leaked fluid is different from incoming fluid, even in a single phase reservoir (GOR/API gradient in reservoirs are common)
- Phase separation - separated fluids are different from the original fluid
- In/Near source cracking, water washing, mixing, gas stripping, biodegradation …

It impractical to predict fluids with bottom up kinetics modeling approach.

Integration of Fluid Properties With Seismic and Geology to Map Source Rocks

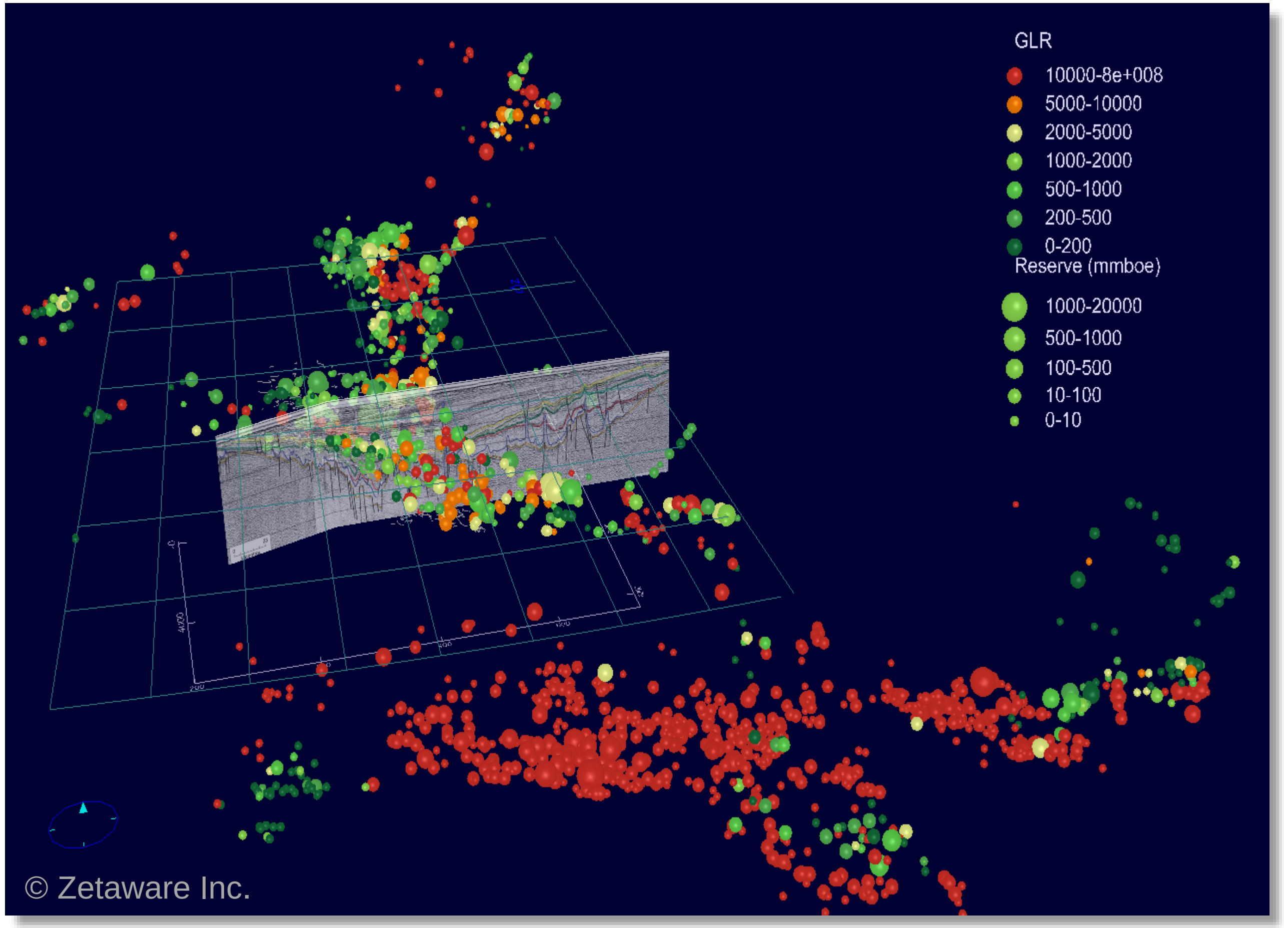




Orange colors are high sulphur oils from Carbonate source rocks, typically low maturity, low GOR and low gravity heavy oils.

Orange colors are Volatile oils and gas condensates deltaic DE Source Rocks.

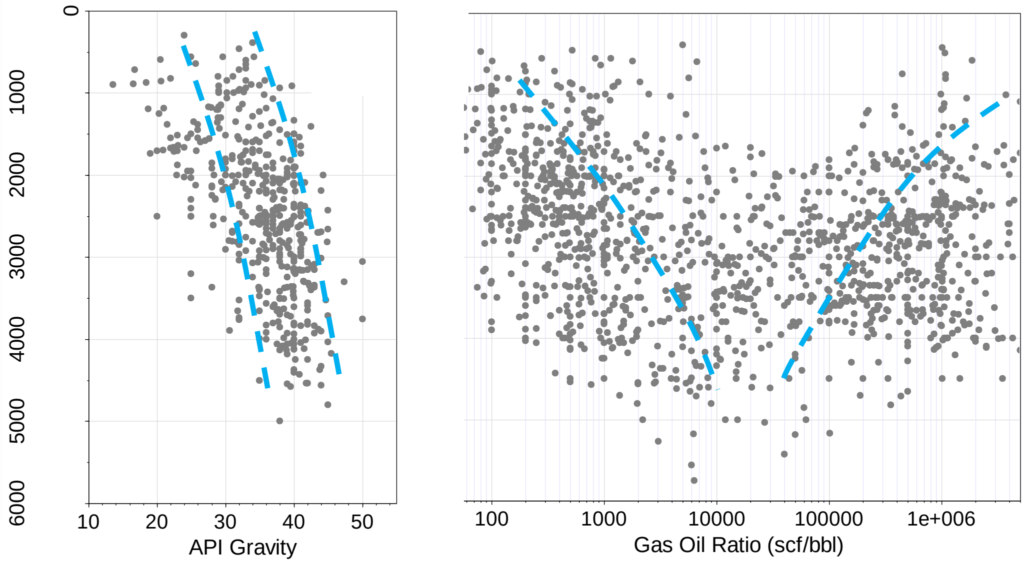
Petroleum System Behavior from Fluid Data



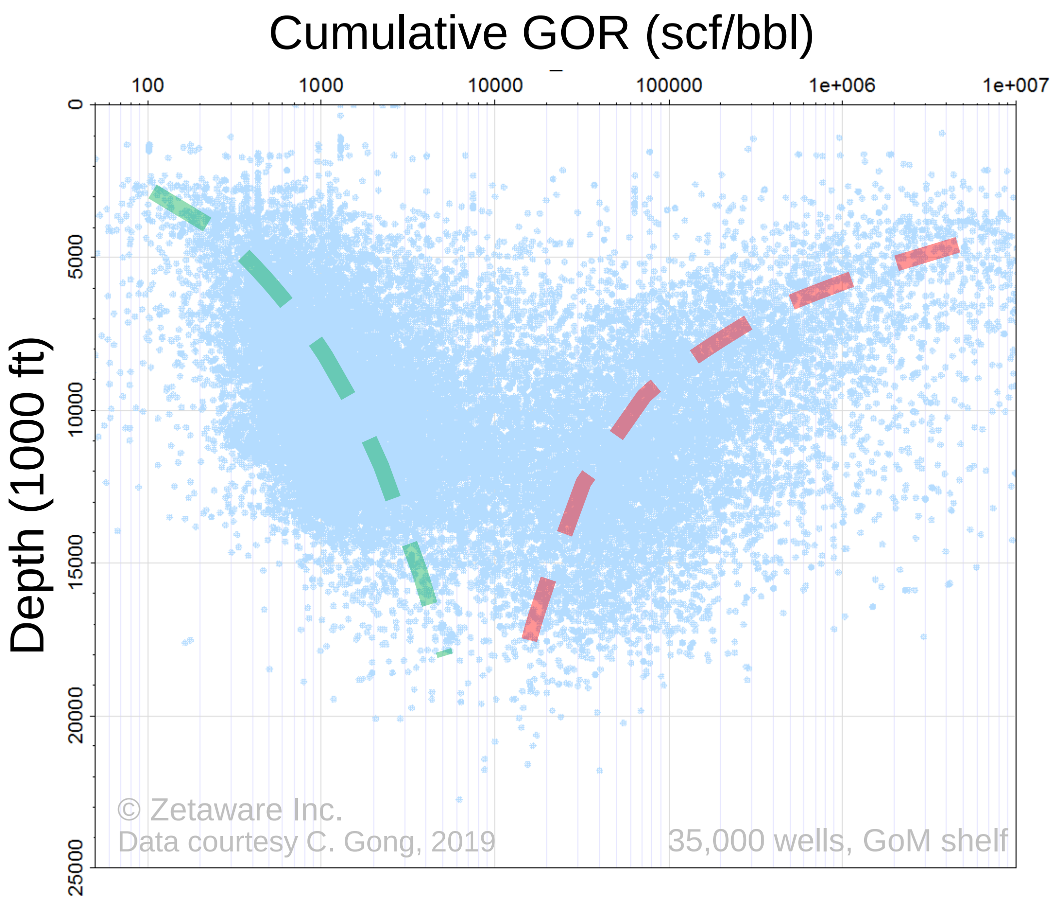
Field data Courtesy of IHS, TGS Seismic, Charles and Ryzhikov, 2015

Observations from big data in geological context can help reveal the dominant processes that explain the observations:

- ❑ Source facies
- ❑ Maturity
- ❑ Migration and PVT effects



Truth In Large Data Sets (Chris Cornford, 1998)

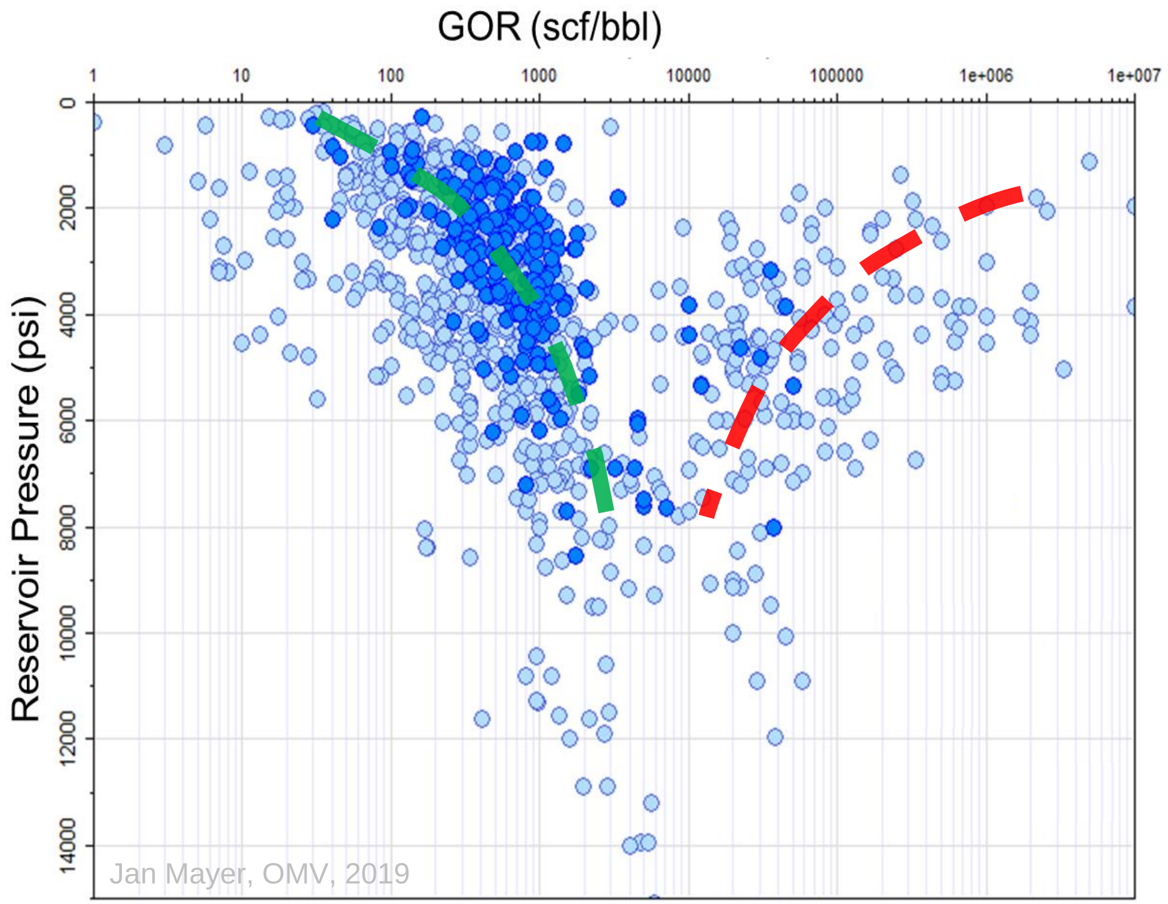


The shape of these two trends are most likely the result of phase separation during migration resulting in less gas in shallow oil fields and less liquid in shallow gas fields.

During upward migration, the HC fluid reaches bubble or dew point pressure, the second phase starts to form, it is less mobile due to low initial saturation and may be left behind along migration pathway.

In some basins the source rock seems to produce enough gas to saturate the oil and enough liquids to saturate the gas.

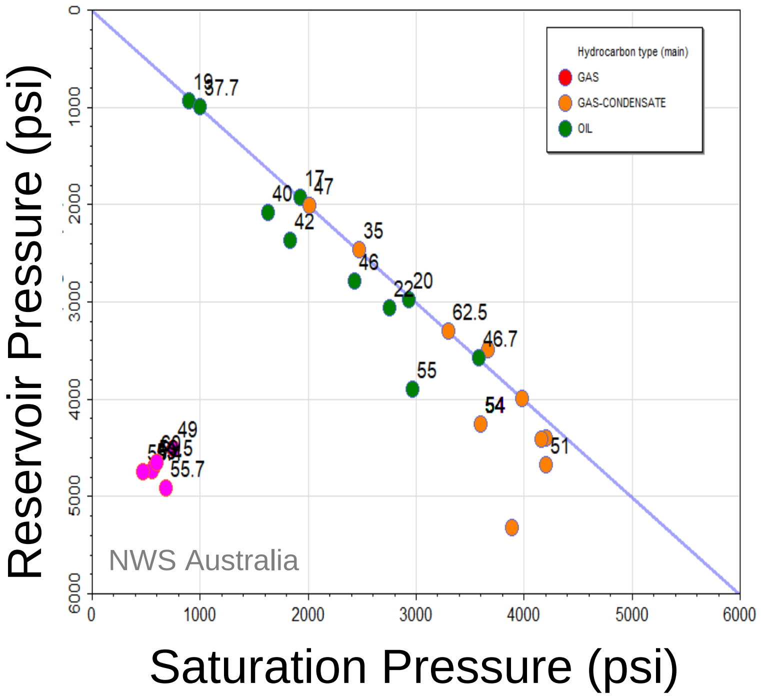
Phase Behavior From Global Fields Data Set

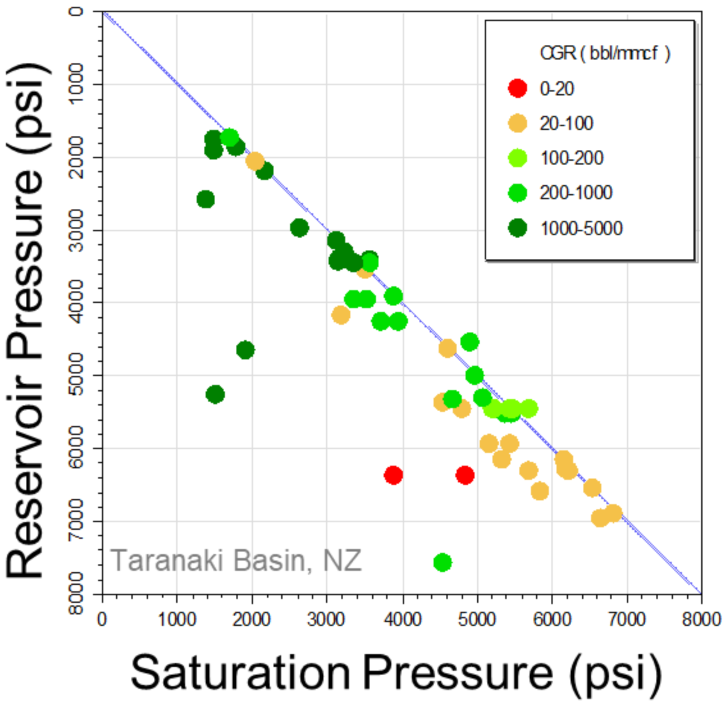


A global dataset of oil and gas fields, showing effects of saturation pressure control of GOR and CGR.

Dark blue points are fields with known gas caps, or oil legs.

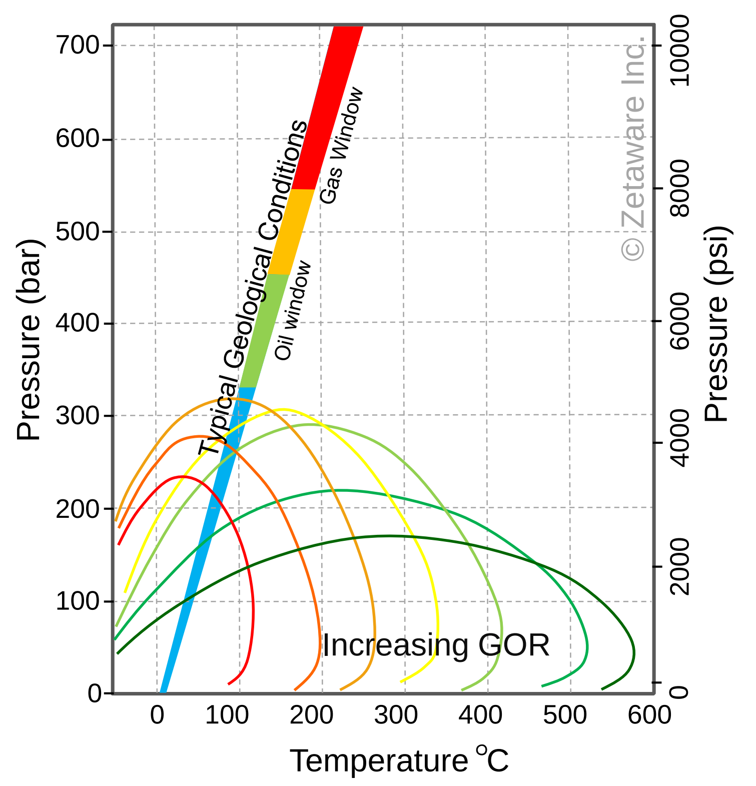
Reservoir Pressure = Saturation Pressure (Psat)



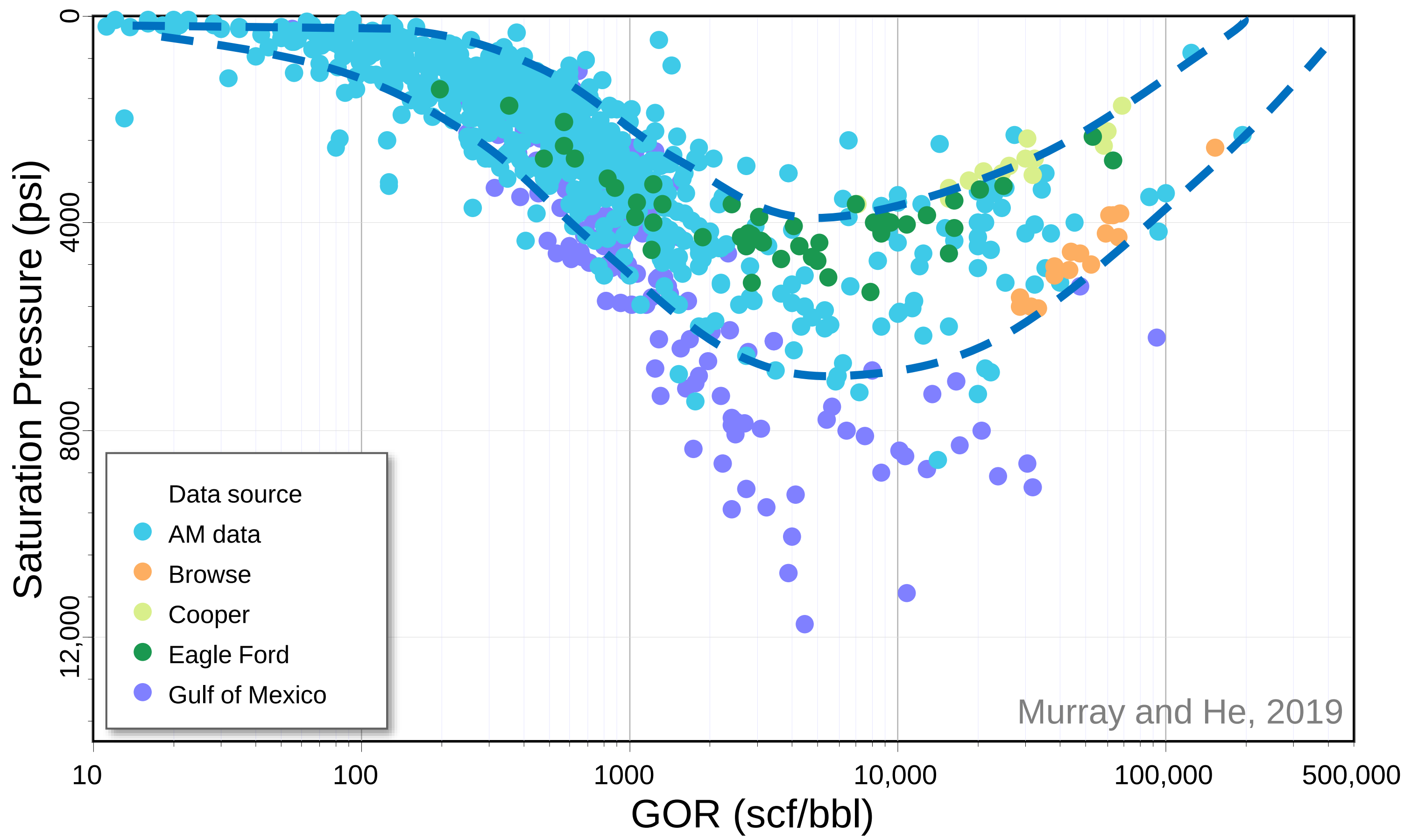


Looking further, we see that in many terrestrial mixed oil and gas systems, Psat and reservoir pressure are equal within measurement uncertainties in most reservoirs. This is consistent with the interpretation of the previous two figures.

Big PVT Data & Petroleum System Implications

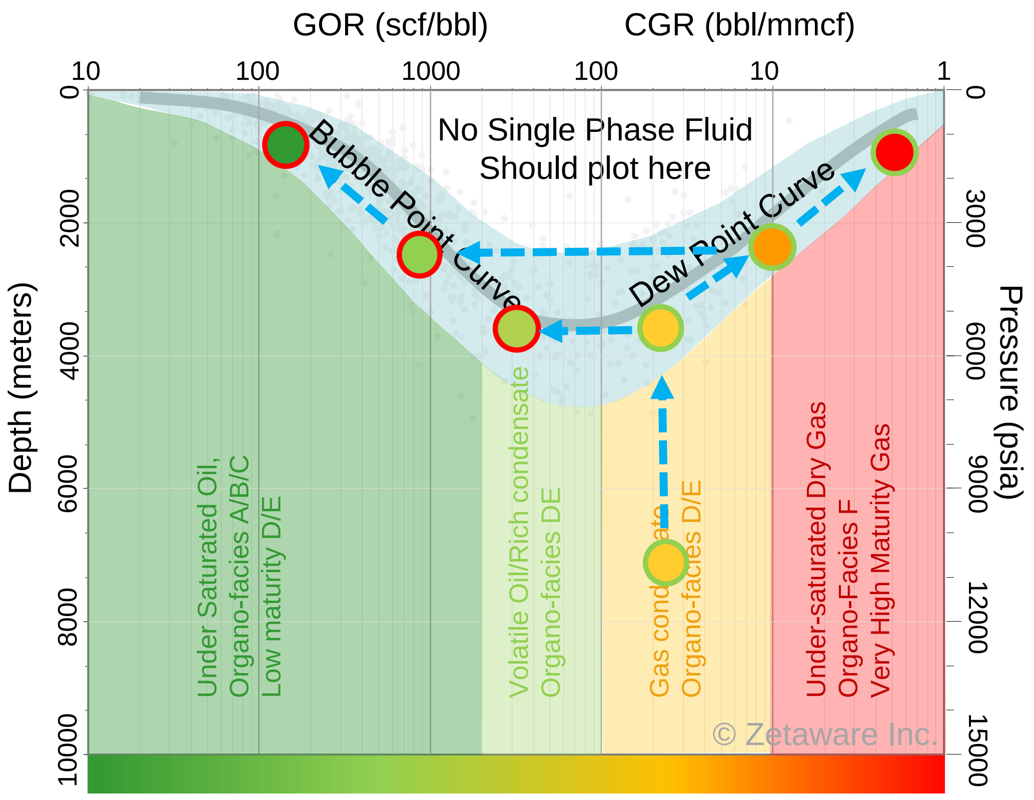


Standard phase diagrams cover much wider range of PT. In basins, we can make predictions based on pressure & GOR.



Saturation pressure and GOR from various databases. Trends are better defined for a specific basin. Purple dots at the bottom (high Psat) are due to mixing biogenic gas with low maturity oil in deep water GoM.

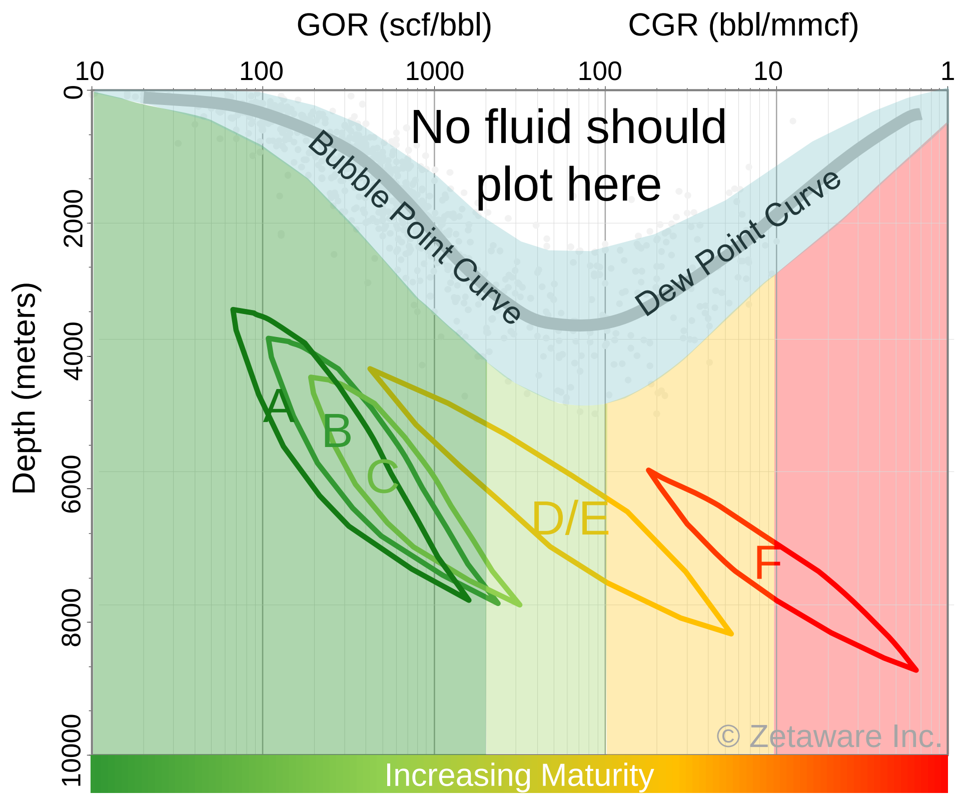
Phase Separation Process During Migration



Simplified global phase prediction template after removing outliers from Psat data

- As a typical gas condensate migrates up and hits the dew point pressure, some condensate/liquid drops out of the vapor phase
- The liquid phase may be less mobile due to low saturation and may be left along the migration pathway
- The gas (vapor) phase continues to lose liquid as it migrates to shallow depths, and becomes leaner (dry gas)
- When separation happens in an accumulation, the liquid phase may spill from the trap and continue on the bubble point path and lose gas to become a low GOR “oil”.
- Similarly the GOR of black oils may also be limited by Psat at shallow depths. This explains the observed GOR/depth trends.

Fluids From Typical Source Organo-facies



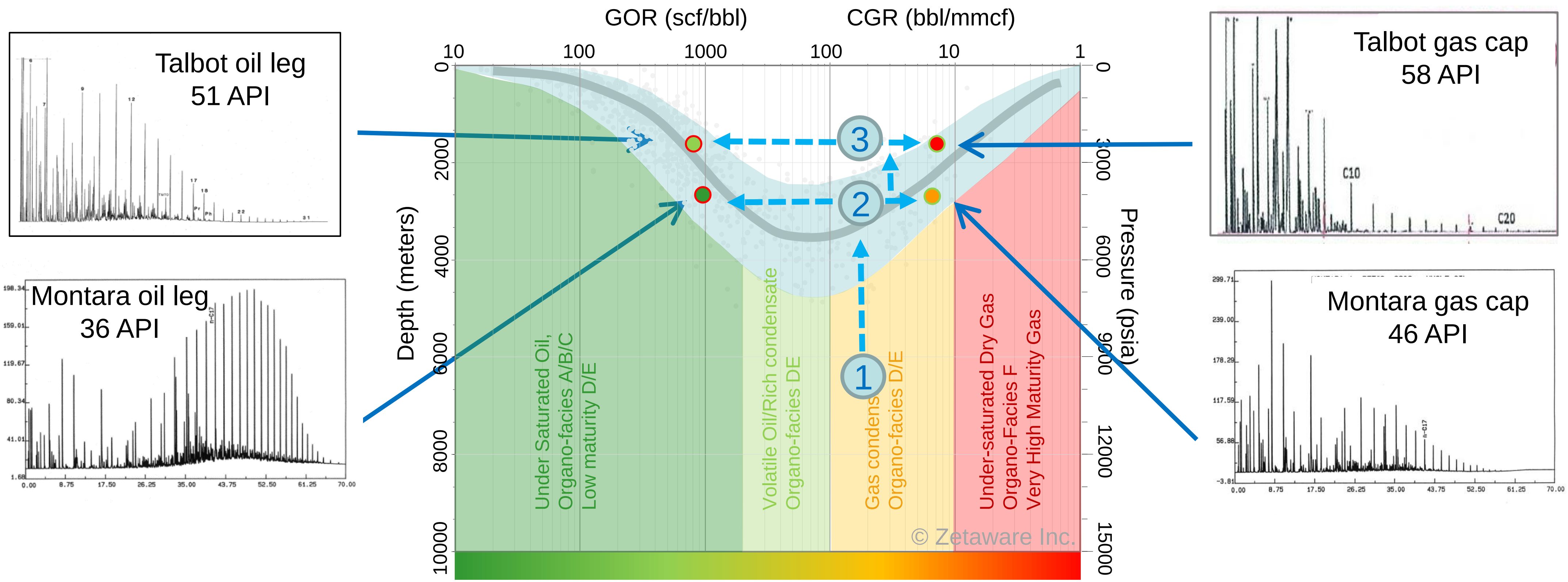
1) Generation windows for all source rock organo-facies occur in single phase region of the phase diagram, **phase separation happens during upward migration, or exhumation**

2) A/B/C systems are less likely to reach bubble point so most fluids are under saturated oils

3) Lean gas systems (F) are also unlikely to reach dew point and therefore typically form undersaturated dry gas fields

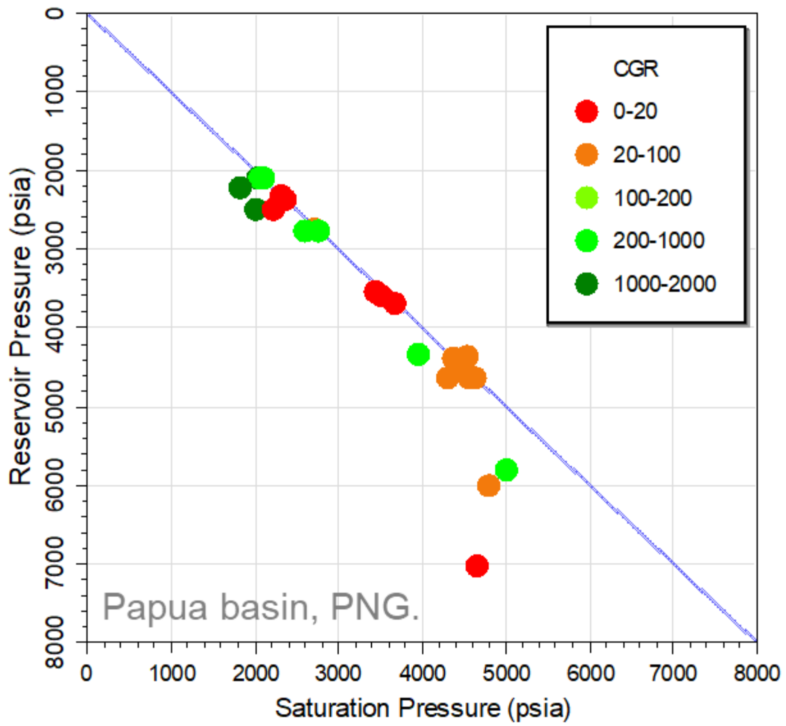
4) DE and mixed source fluids are the most susceptible to phase separation as the generation window is close to saturation pressure, and can lead to dual phase (oil and gas) accumulations

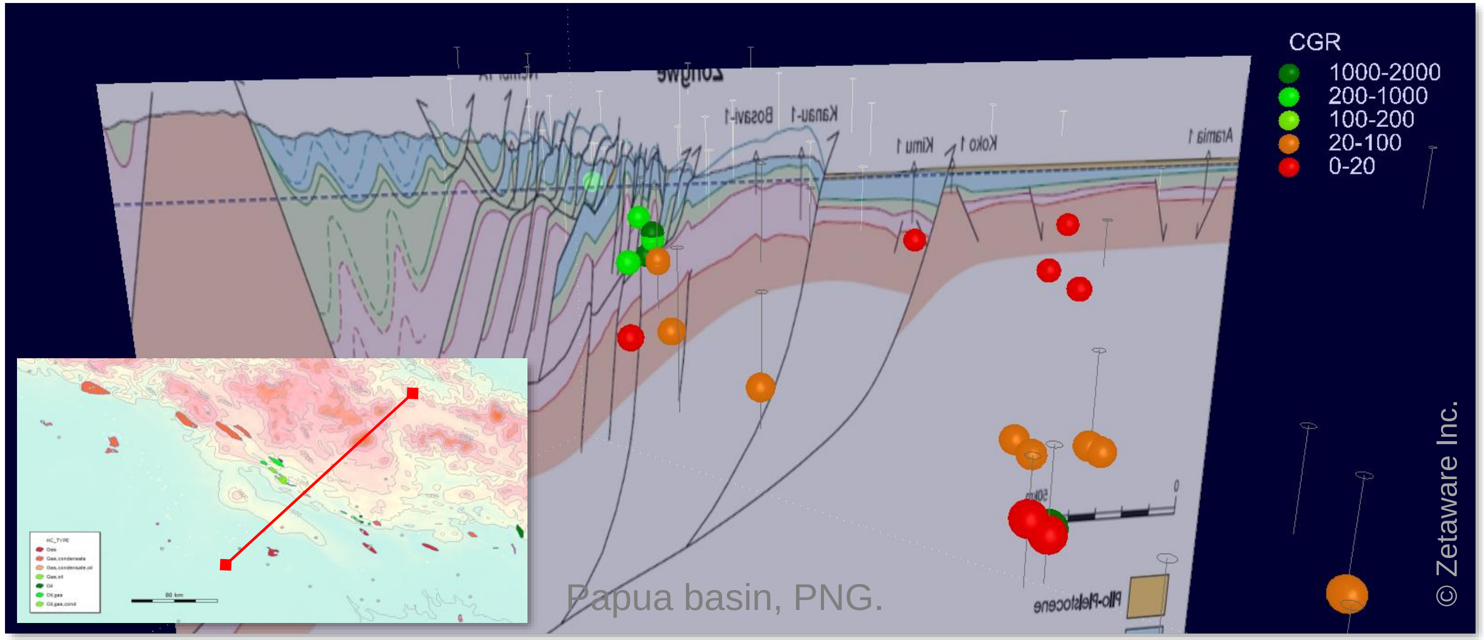
Phase Separation Effects - Vulcan Sub-basin Example



1. Incoming charge typical of the area, GOR ~20,000 ~43 API gravity
2. Reaches dew point, waxy liquid drops out as 36 API oil leg, gas cap has 46 API condensate
3. With further migration to lower pressure, lighter oil (non waxy) drops out, and gas condensate becomes even lighter and saturates rich, Psat decreases as well.

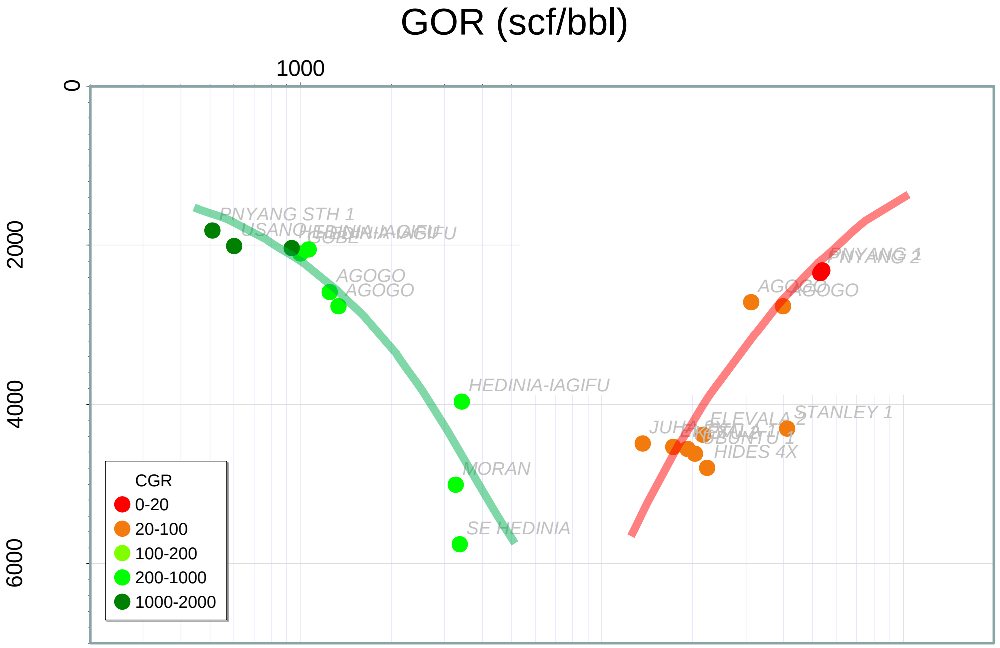
Pressure Control on Fluid Phase and Properties.





We can tell that most fields in the area are saturated (left), and oil fields are associated to a certain structure domain by plotting data in space.

Predicting GOR/CGR, PNG Example



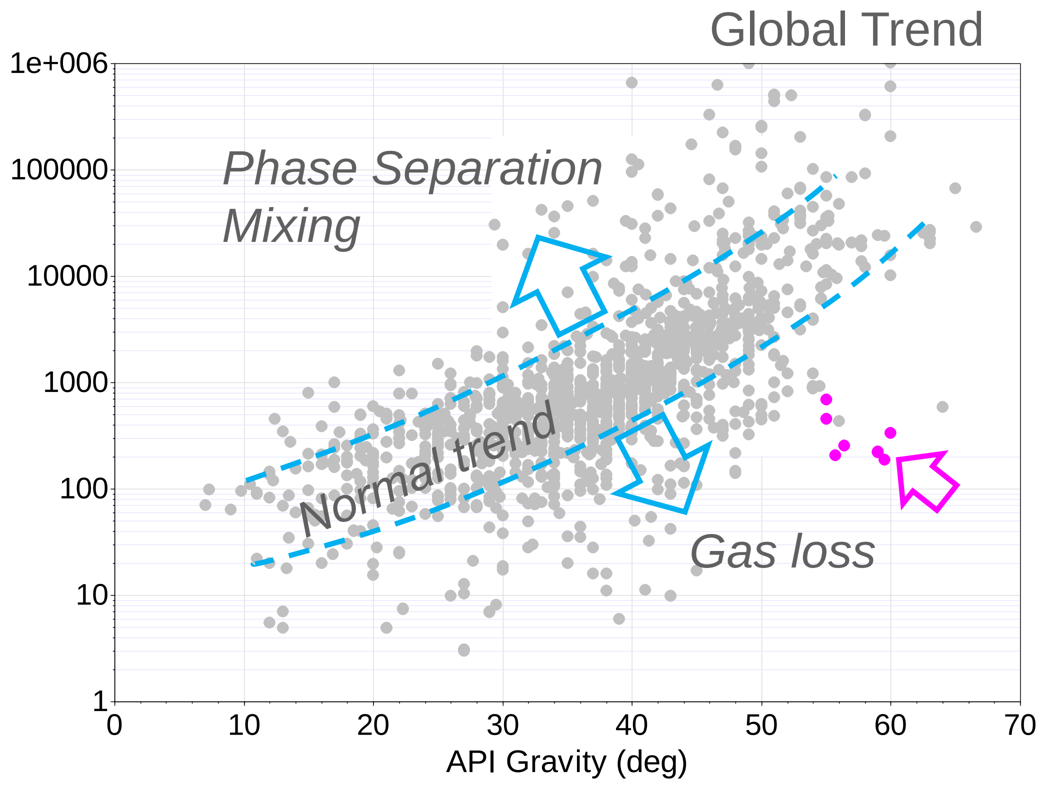
Lukasz Krawczynski, 2019

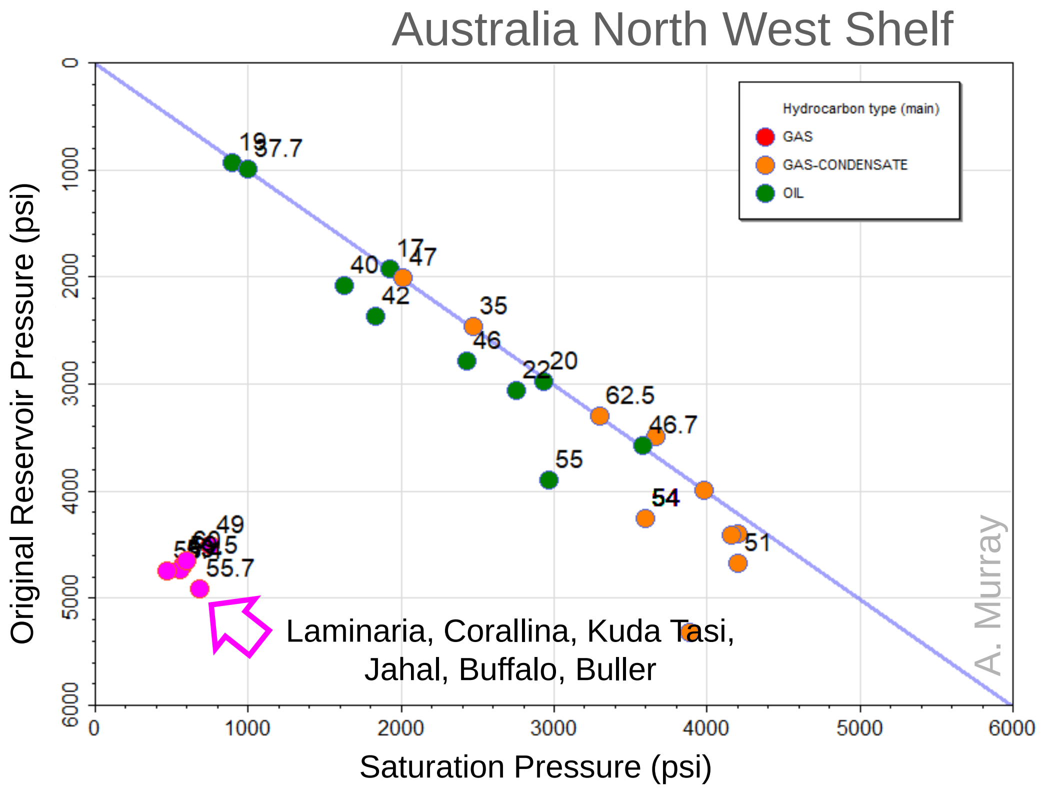
Papua Basin, PNG

- ❑ The gas and oil ratios of the fields, for both phases, clearly follow the bubble and dew point curves: **Reservoir pressure can be used to predict GOR/CGR**

- ❑ Simple but useful relationship allows geologists to predict GOR and where to find liquid-rich gas

Knowing What's Normal Can Help Infer Processes

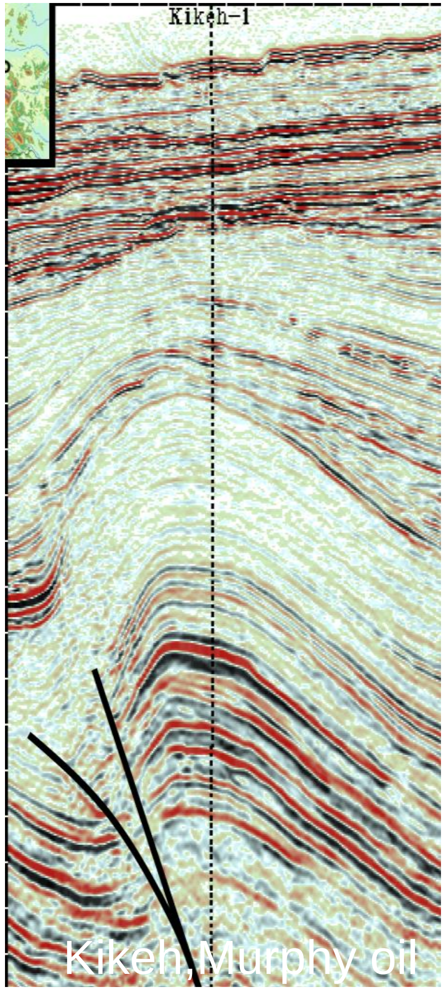


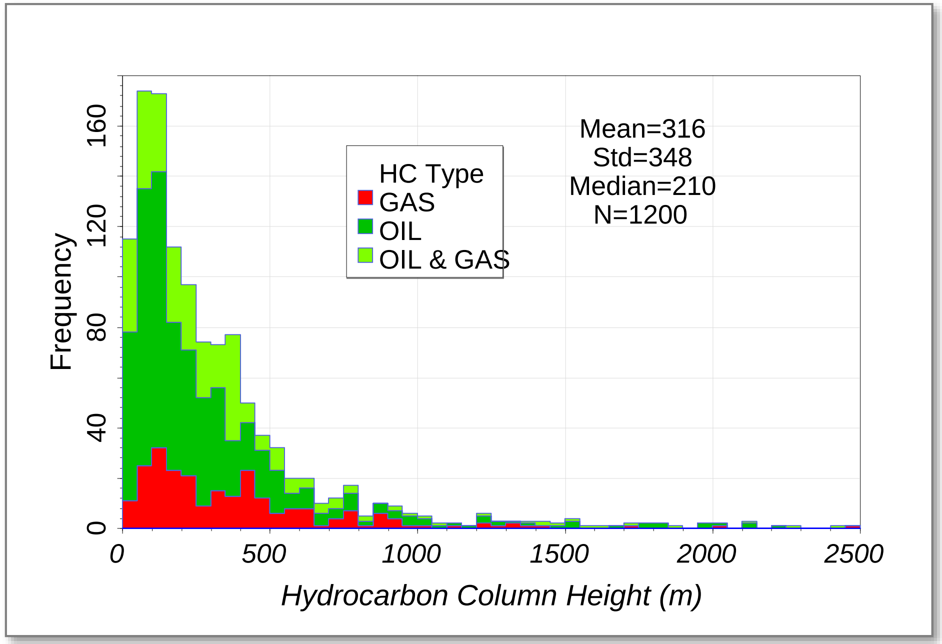


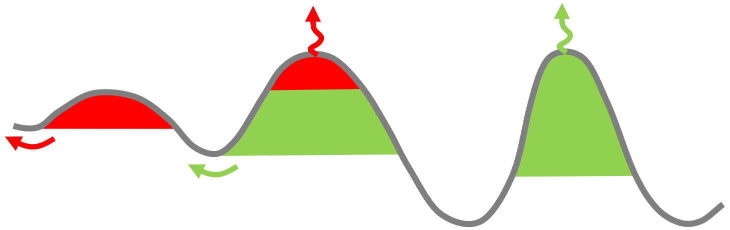
- Incompatible API and GOR is a tell-tale for alteration, migration mixing or production phase separation
- Need large data sets to establish perspective

- Several "oil fields" in the Northern Bonaparte Basin (pink) have the high gravity but are low GOR and undersaturated
- They have lost gas due to phase separation & leakage and/or water-washing and were originally gas condensate

High Structure Relief Promotes Stacked Pay and Oil Accumulation In Dual Phase Systems.







Seal Strength vs Closure

"A Fundamental Control on the Distribution of Oil and Gas"

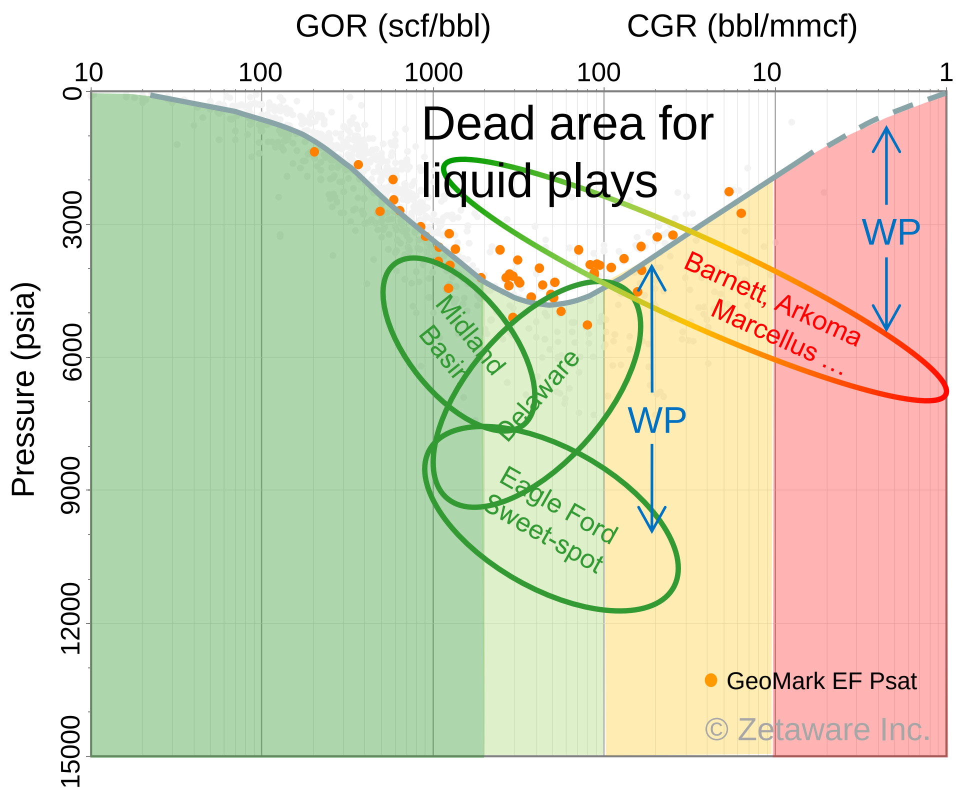
J. Sales 1997

Left: The Kikeh field of Malaysia – stacked pay in a higher relief structure – gas leakage and preservation of liquid phase due to its high relief

Right: Global median of HC column heights is about 200 meters. Taller structure closures may lead to capillary leakage of HC and vertical migration, and form stacked-pay reservoirs. Marine shales are better seals than non-marine shales

Bottom: High relief structures tend to leak off excess gas and retain oil columns, and low relief structures tend to retain gas phase

Phase Risking in Shale Plays



Simple Predictive Rules:

1) Better economics if <u>working pressure</u> (WP = P – Psat) is high. Low WP is high risk for phase separation and GOR increasing during production

2) Dry gas plays are low phase risk due to low dew point pressure, and pressure retention by gas expansion

3) Areas of liquid play with significant uplift are not likely to be economical

Conclusions:

- Fractionation processes during expulsion and migration and complexity of the plumbing system make it impractical to predict fluids with any bottom up modeling approach
- Phase separation exerts significant control of fluid type, GOR/CGR as well as composition at shallow depths (typically <~4000 m). These can be predicted empirically with a simple Psat-GOR relationship.
- In dual phase systems, trap closure and seal capacity factors favor liquid in tall/leaking traps and gas in low relief/spilling traps (Sales 1997)
- Maturation and migration processes favor low maturity, low API and low GOR fluids in basin margins and shallow reservoirs. Lighter, high GOR fluids are found in deeper reservoir and near kitchens. Oil accumulations tend to be above and outboard from gas accumulations
- The essence of top down petroleum system analysis is the consideration of the properties of the whole fluid, and the ability to visualize and interact with data in PT space and geological context

Referemces:

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