



Enabling Hydrocarbon Exploration through Microbiome Analysis

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Summary

This article provides new empirical evidence in support of the hypothesis that nearly vertical leakage from hydrocarbon accumulations all the way to the surface takes place and produces a signal that can be directly or indirectly inferred. It demonstrates that analyzing the ecology of microorganisms in the shallow subsurface can be used as a powerful technology for hydrocarbon exploration. As elaborated on in this article, the microseepage phenomenon is an integral part of the overall hydrocarbon migration process taking place in the subsurface. Our technology exploits the fact that microorganisms living in the soil are affected by the increase in the hydrocarbon concentrations in their environment. There are very many (tens of thousands) different species living in the soil that, due to evolutionary forces, exhibit extremely complex interactions with their environment and among themselves. For this reason, this technology could only be possible now, with the help of the substantial recent innovations in genomic sequencing and machine learning. The success of this technology is demonstrated in a USA-based case study. This is one of many projects we recently executed that shows that this methodology, in the given settings, supports with great confidence an increase in the probability of success (POS) of the exploration campaign.

Microseepage and its place in the greater scheme

The existence of the microseepage phenomenon has been reported in numerous articles starting in the first half of the 20th century (e.g., Laubmeyer, 1933, Davis, 1956) to the present day. Microseepage has been observed in the form of concentration anomalies located directly above subsurface hydrocarbon accumulations, that exhibit sharp edges and are tightly correlated with the production activities. This short reaction time has been observed in connection with gas storage sites when the anomaly would be present before the winter and would disappear in the spring (Tedesco, 1999). Other authors have reported the presence of halo patterns in the anomalies (Schumacher, 1996), which suggests that the volumes of gas seeping to the surface are small enough to become unmeasurable under the action of subsurface chemical and microbiological processes. Therefore, the microseepage signature can be summarized as follows: a fast, vertical transport of tiny volumes of light hydrocarbons.

Several authors investigated the physical mechanisms that can explain the microseepage phenomenon (e.g., Price, 1985; Klusman, 1993; Klusman and Saeed 1996; Brown, 2000). The individual mechanisms explored were diffusion, bulk viscous flow through fracture systems, migration in water solution, and migration as micro gas bubbles (bubbles at colloidal size) pushed upwards by buoyancy. Nevertheless, they all take place simultaneously with the latter having the highest weight. After extensive literature reviews, we concur with this conclusion as well. Additionally, we believe that instead of being a distinct phenomenon, microseepage is a core part of the hydrocarbon migration process, which is nothing more than the summation of all physical forces and interactions acting at a microscopic level on the infinitesimal volume of fluids, corroborated upwards to the macro level.

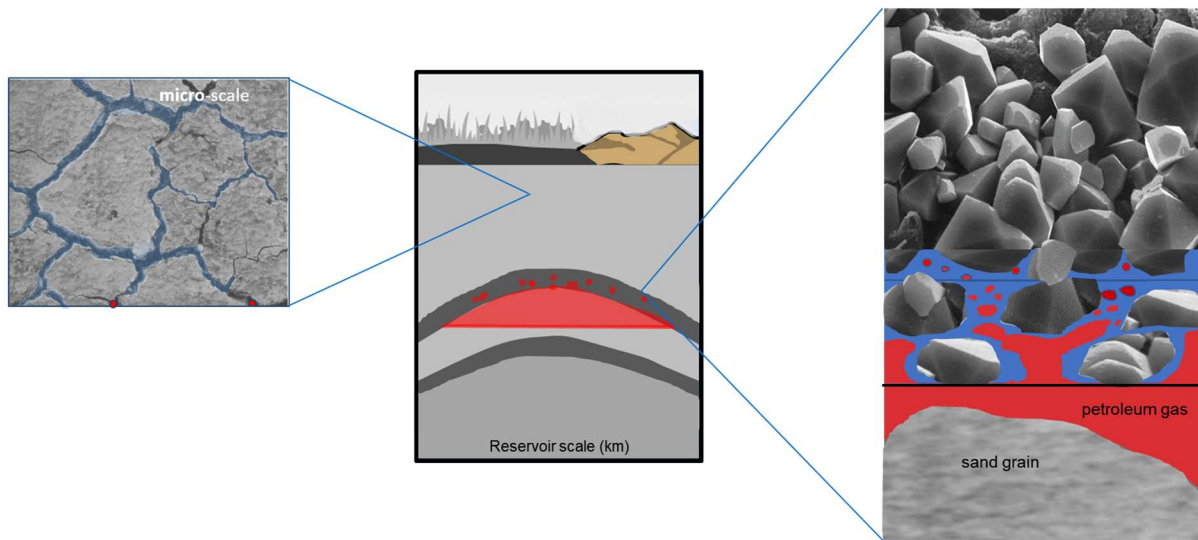


Figure 1. Initiation and upward migration of petroleum gas microseepage.

The fluid flows in the subsurface are modeled, starting from the fundamental laws of mass and momentum conservation for infinitesimal volumes, by the well-known Navier-Stokes' equations. Considering the reservoir conditions and the corresponding properties of the fluids we arrive at the simplified well-known Stokes formulation: $\nabla U = 0$, $\mu \nabla^2 U = \nabla P - \rho g + C$, where μ is viscosity, ρ is density, g is the gravitational acceleration, U is the fluid velocity, ∇P is the pressure difference and C are the combined capillary forces. From these equations, we can conclude that the fluid migration in the subsurface is driven by the combined interaction of gravity, pressure, viscous, and capillary forces. The complications arrive from the fact that, in the subsurface, we are dealing with multiple fluids compositions and phases. With this, the capillary forces (the obstacle the invading fluid needs to overcome) become more important since we need to consider all interactions with the rock and the various fluids as well. Finally, we need to realize that we are dealing with a migration flow regime, where buoyancy and capillary forces dominate the flow equations, as opposed to a production flow regime, where the pressure difference replaces buoyancy. As England also argues (England, 1987), Darcy's law is inadequate to describe the multi-fluid, multiphase flow during migration. In fact, Darcy's law is a macroscopic law that considers volume averaging and assumes continuous flux (Whitaker, 1986) and does not strive to model fluid interactions at a low level in the first place.

In the usual case of upwards hydrocarbon migration, due to the density difference, the buoyancy force is pushing the less dense hydrocarbons upwards. Also, since the denser fluid, overlays the less dense hydrocarbons, gravity (the "engine") acts as a destabilizing factor determining an unstable flow regime (Rayleigh-Taylor instability, Gopalakrishnan 2020). At the critical column height (Berg 1975) buoyancy wins against the capillary forces, and the hydrocarbons will form viscous fingers inside the seal water (England, 1987) that will snap-off due to water pressure (Vasseur, 2013) and continue upwards as discontinuous ganglia with no pressure communication among them (Carruthers et. al.,1998/2003). Local accumulations are possible, where the pressure increase would result in a lateral deviation towards an accumulation (England, 1987).

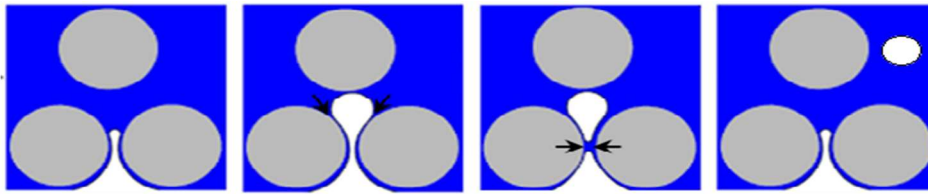


Figure 2. The snap-off repetitive process (left to right). The water flows down and exerts pressure on the finger as shown by the black arrows (picture adjusted from Almajid and Kovscek, 2015).

This is the register where microseepage takes place, the main difference being that it consists of light gas (C1-C5) leaking at low flux through the seal of a source or reservoir. Due to the much lower density, the gas buoyancy is much larger, the critical height is smaller, and the flow potential is larger and nearly vertical (England 1987), and due to the low flux, the viscous fingering and snap-off are more pronounced (Tian 2020). Due to the higher velocities in the carrier rock, the local accumulations are less probable for gas. Once a gas volume is snapped off, it will form nearly spherical bubbles (minimal surface), as shown in Figure 2, that will be pushed upward by buoyancy according to Archimedes' principle. Due to the opposing drag force exerted by the water, the terminal velocity (Stokes's law) for a bubble with a micrometer radius is in the range of 10 to 1000 meters per year (Brown, 2000), which closely agrees with the empirical observations. Figure 1 shows a sketch of the microseepage phenomenon as described above.

In conclusion, microseepage is a phenomenon embedded in the hydrocarbon migration overall scheme that is emerging from a very complex interaction of various physical processes happening from nano to micro and millimeter scales.

From microseepage to hydrocarbon exploration

Our technology assumes that the tiny gas volumes that reach the surface will induce slight variations in the soil chemical properties inhabited by a complex community of microorganisms. Also, often, neither the gas volumes nor these variations can be measured by physical instruments. Nevertheless, the evolution of a group of bacteria in this ecosystem is changed. Some bacteria degrade light hydrocarbons as a source of carbon and are recently extensively studied as a possible mitigation solution for pollution with hydrocarbons and their derivatives. However, other bacteria are negatively affected by the change in environment, not only due to a possible increase in toxicity but more often due to the increased competition with the opportunistic species. This realization is what makes our approach stand out as a geochemical hydrocarbon technique, as our models make use of the full distribution of microbes' diversity and abundance.

The workflow deployed was first introduced in 2017 by te Stroet et. al and consists of four steps: (1) collection of small soil (or seabed) samples from locations with known prospectivity; (2) sample "fingerprinting" in terms of bacteria diversity and abundance through Next Generation Sequencing; (3) modeling with machine learning algorithms for confident and accurate predictions; and (4) prediction on the target set using an aggregated response from thousands of models.

For sequencing, we use a state-of-the-art pipeline designed by Biodentify that maximizes the recovery of the genetic material. The sequencing targets the 16S rRNA gene that is extensively used as a molecular marker in phylogenetic studies of bacteria, due to its ubiquity and slow rates

of evolution. This gene consists of 9 variable regions, used for classification, interlaced with conserved regions that provide an ideal target for primers selection.

Our proprietary pipeline makes use of bioinformatic algorithms (DADA2, Minimum Entropy Decomposition, de-novo, and reference-based clustering, etc.) that detects and eliminates errors and clusters together artificial fingerprint details to increase the signal to noise ratio. For this, we combined several 16S ribosomal databases, such as GreenGenes, NCBI, SILVA, Ribosomal Database Project, Genome Taxonomy Database, and, since our samples come from currently unexplored environments containing many uncultured species, our curated dataset.

We use machine learning models able to find fine correlations between data and the presence or absence of microseepage. To increase the prediction accuracy and our confidence in them, we employ a cross-validation approach, widely used in machine learning. This is one of the strengths of the approach because it produces not only models that fit the training dataset, which could result in overfitting, but models that are optimized for prediction on new samples. Additionally, this approach allows us to generate predictions that are the aggregating response from thousands of models, together with a confidence measure on their likelihood. Since, in the reported project below we used a “blind” set (a collection of samples with unknown locations for us, thus for all intended purposes just like a target set, but for which our client knew their location) our predictions could be retrospectively objectively validated.

Demonstrating the technology on unconventional plays

Approached as a proof-of-concept study, part of an awarded research grant by the EU Horizon H2020 fund, the goal of the project was to confirm whether our technology applies to unconventional oil and gas plays. The Eagle Ford Shale Formation of Texas was chosen as both an unconventional oil and gas play, whereas the Bakken Shale Formation of North Dakota is a purely unconventional oil play, with the detailed goal to check whether we can distinguish between high and low producing wells.

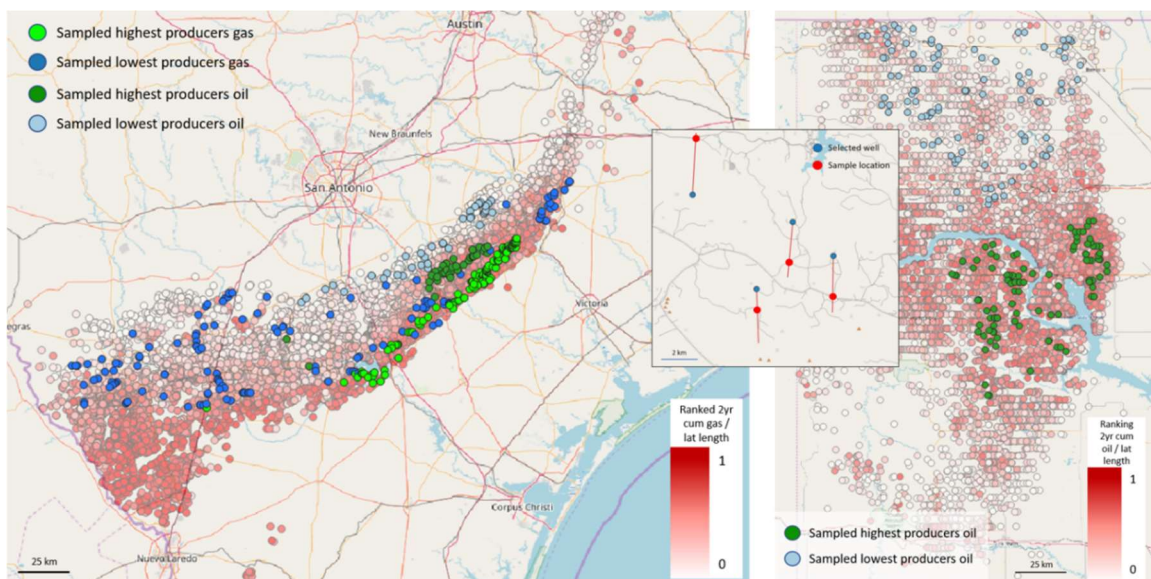


Figure 3. Samples' locations: Eagle Ford Shale (left) and Bakken Shale (right). Red/white dots show all drilled wells per play, blue/green dots are sampled wells. Inset shows how the sample location was optimized for easy access from public roads.

Since both plays have seen extensive E&P activities for over two decades, the design of the data acquisition campaign was focused on identifying those easily accessible locations with confidently known production statistics. In total we gathered 540 samples (on 34,000 km²), as showed on the map in Figure 3, divided into sets as follows: a) Eagle Ford Shale, 135 from each low and high production gas wells, b) Eagle Ford Shale, 35 from each low and high production oil wells, and c) Bakken Shale, 100 from each low and high production oil wells. The distinction between low and high producers was based on a 2-year cumulative production. To validate our predictions, 200 samples were blinded and relabeled by our customer.

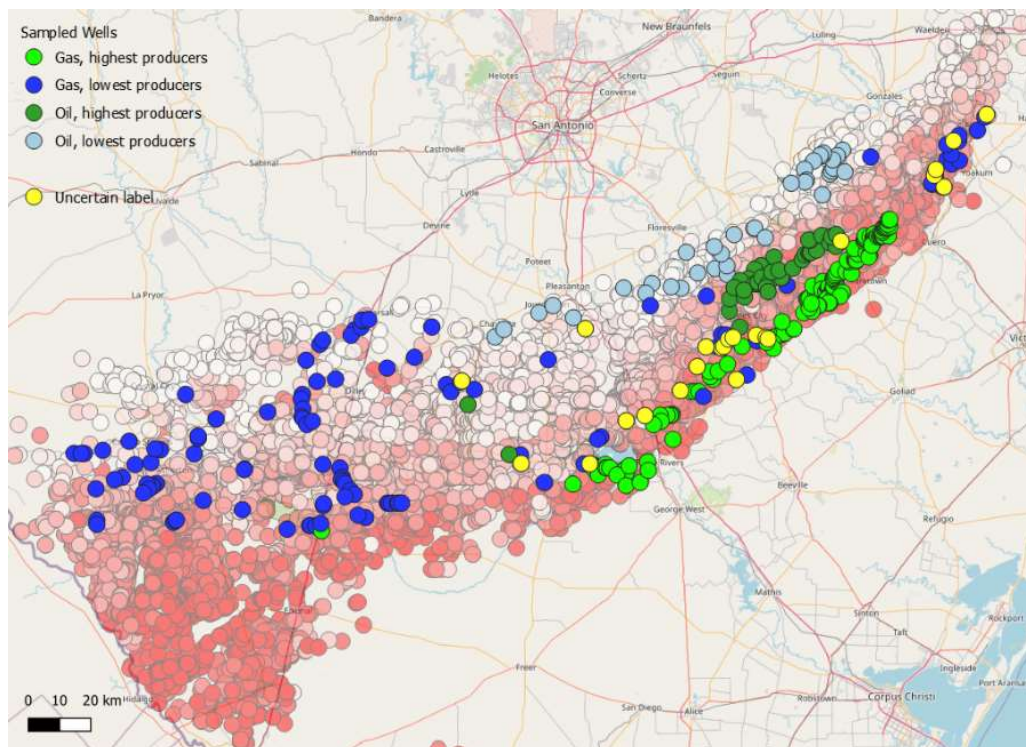


Figure 4. Eagle Ford sampled wells (blue/green) and in yellow the training samples that were identified as having larger prospectivity uncertainty.

The prediction accuracy score calculated as the ratio of the number of correctly classified to the total number of samples analyzed was used as the performance measure. Following our cross-validation scheme, we report an expected accuracy score with its confidence interval. This approach is essential since we strive not only to get accurate predictions but manage their uncertainty too. Based on this approach we could also identify which samples are confidently predicted, by a large agreement among all models, and which are not. This is useful for projects like this one where the distinction in prospectivity is a matter of an arbitrary choice. Figure 4 shows the set of such sample locations in the Eagle Ford Shale.

The expected accuracy as calculated based on the triple loop approach, was for this dataset 82% \pm 5%. In retrospect, based on the actual labels for the blind dataset, our client computed the exact performance score to be 85% which is very much in the uncertainty range we expected.

Conclusions

Microseepage is an integral part of the hydrocarbon migration process that is taking place at a microscopic scale under gravity. The analysis of the ecology of microorganisms that live in the shallow subsurface is a very powerful tool for hydrocarbon exploration. The technology has been proven with great success in a project in the Bakken and Eagle Fort Shale plays.

Acknowledgements

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