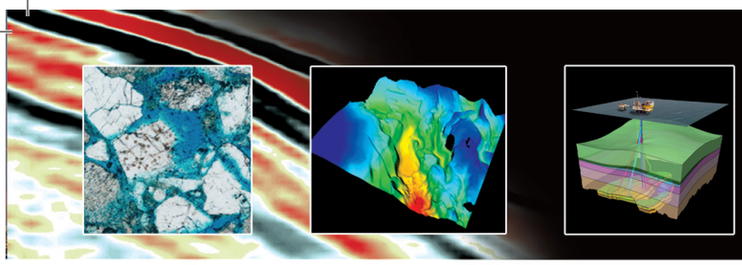

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Petroleum Systems Analysis 'Science or Art?'

24-25 April 2019

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Petroleum Systems Analysis ‘Science or Art’?

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16.10	**The Thermal History of the Weald Basin, southeast England** Tanya Beattie, *University of Southampton*
16:35	**Some physical considerations of the kinetic models for predicting petroleum generation in geological basins** A. D.Carr, *Advanced Geochemical Systems Ltd*
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UK North Sea oils geochemistry: Interpreting newly acquired data from legacy oils Akinniyi A Akinwumiju, *Integrated Geochemical Interpretation*
Geochromatographic separation of organic tracers using a natural Draupne (Kimmeridge Clay) source rock column Florian M. Panitz, *Kiel University*
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A geochemical analysis of Triassic source rock of the 7th member of Yanchang formation in Erdos basin, China —— the comprehensive effect in paleoclimate, biological thrive and the potential lacustrine current Xiaoxue Liuzhuang, *PetroChina*
Demineralisation Study Shows Preferential Oil Storage in Kerogens within mature Kimmeridge Clay in the North Sea Munira Raji, *Durham University*

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Organic geochemical insights into the Cretaceous Western Interior Seaway Libby Robinson, *University of Southampton*
Petroleum system analysis and prospect identification using a multi-attribute volumetric approach Gaynor Paton, *GeoTeric*
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Hydrocarbon Generation and Migration modelling of the Barremian-Aptian Source Rock unit of the northern Orange Basin, South Africa C. Samakinde, *University of the Western Cape, Capetown*
Analysis of Petroleum System in Mahu Sag of Junggar Basin, Northwest China Jian Wang , *PetroChina*
Combining modelling dimensions, software and states of mind in PSA: an application to the Namibe Basin, off southern Angola Tiago Cunha, *IGI Ltd*
Assessment of the Golden Zone for the Norwegian Barents Sea through estimation of net erosion and petroleum system modelling Jesper Kresten Nielsen, *MOL Norge AS*

Oral Presentation Abstracts (Presentation order)

Session One:
'Big Data' – What's it all about?

KEYNOTE: The uncertain art of science in petroleum systems

Dan Cornford
IGI Ltd

The question we address in this conference lies at the heart of science and is a subject Chris and I discussed frequently. Science is built on the experimental principle, and falsification. Observation and measurement provides the means to capture the response of the system in experiments. Mathematics and logic provide the framework for reasoning and modelling. Statistics connect experiments and models (reality and abstractions) and is the ground where art and science meet, in uncertainty.

> **Art**: the expression or application of human creative skill and imagination.
>
> **Science**: the intellectual and practical activity encompassing the systematic study of the structure and behaviour of the physical and natural world through observation and experiment.

In the context of oil and gas exploration the role of data and models remains subject to a range of opinions. The physical-chemical petroleum system is governed by the laws of nature. However, across the scales of interest (molecular to nearly planetary) there remains significant uncertainty, arising from a range of sources. A key uncertainty relates to the initial and current state of the Earth system within which the petroleum system is, literally, embedded. There also remains uncertainty in the chemical dynamics at the molecular scale, mainly related to the complexity of the molecules involved. The physical dynamics are relatively well understood, although their interaction with the uncertain multi-scale physical subsurface structure creates significant additional uncertainty.

The role of models and modelling

It would be possible to construct, from our current scientific understanding of nature, a bulk dynamic model of the evolution of the petroleum system, from the deposition of the organic material, its burial and heating, through the molecular dynamics leading to oil and gas formation, the physical expulsion, migration and fractionation, and even biodegradation. Not all parts of such a model could be written as well-defined differential equations, and the forward solution of such a model would be computationally extremely challenging. But possible. We know it is possible because we use basin models.

If we built such a model, would the result look anything like our observed world? Maybe. If so, such a model offers great promise because by conditioning the model on observations (data assimilation or inference) we would be able to predict where, what sort, and how much oil and gas there would be. This is petroleum systems analysis and calibration. The art comes in defining possible depositional, burial, heating, and migration scenarios that lead to results sufficiently consistent with the observations. The space of possible models (hypotheses if you like) is uncountably large, so expertise and experience must guide us.

Truths in large data sets

Another scientific approach, not necessarily antipathetic, would be to explore large data sets, and from correlations or analogues found in the data, predict where, what sort, and how much oil and gas there might be. By using observation, and our own geological understanding we can find patterns and predictability that enable us to interpolate, or extrapolate, from the observations into areas where we have no direct measurements. Such 'truths from large data sets' empirically capture the influence of the underlying system dynamics but add uncertainty due to sampling and density of observation, observation noise and representativity errors and the heterogeneity of nature.
When using data driven approaches to exploration we also need to account for a range of uncertainties, and the value in our predictions will depend on being able to quantify these uncertainties which is especially challenging in the extrapolation case. Again, this is where the art comes in, along with the intuition to look for particular signals or patterns.

Competing or complementing

Data science, or machine learning / statistics, provides us with tools and models to help summarise and make predictions using observations; the data driven approach. Science and dynamical system models provide us with

tools to help make predictions; the model driven approach. Although often cast as competing approaches, both model and data driven approaches are complimentary.

To understand the similarity of the two approaches it is important to recognise that data driven approaches still use models – either conceptual models based on human intuition or computational models based on a variety of statistical and machine learning methods. All statistical models, such as regression models or neural networks, assume some sort of regularity or continuity to interpolate or extrapolate based on a finite set of 'training' observations.

Similarly, all physically motivated system models are based around conservation principles at their heart. Above molecular scales such models can actually be seen as constraining the solution space of the representation of the system under consideration to a (complex) class of (often smooth) functions. It is possible to see system models as very complicated constraints to help interpolate the observations.

A consistent framework that embraces art and science

There are many frameworks that can be used to understand the interaction between science, reality and art. The subjective Bayesian framework is the closest I have seen to a consistent framework that allows for a scientific approach while readily including artistic endeavour.

Adopting a Bayesian approach will feel natural, if not familiar, to most scientists. A key concept in all Bayesian approaches is the treatment of uncertainty. Most commonly a probabilistic approach is adopted. It is important to recognise this uncertainty largely arises from a lack of information – the systems themselves do not have to be stochastic. We can have an incredibly simple, predictable, even linear, system but if we do not know the initial conditions perfectly we will never know the current or future states without some uncertainty.

Thus if we think about a particular system, we can construct a range of simpler (data driven) or complicated (model driven) models that represent aspects of the system we are interested in making judgements about. These models will be functions of some type, in that they will have inputs and produce outputs, and depend on a set of parameters. The form of these functions, together with judgements about the uncertainties in the parameters and outputs will define our prior beliefs about the system of interest. These define a distribution over the space of functions (or hypotheses) which we believe are plausible descriptions of the system of interest. The art comes in our ability to imagine the scenarios, and quantify our uncertainty in the model.

An important consequence of this approach is that two different people are likely to have different prior beliefs about a given system, and thus will produce a different distribution over the space of functions. This is natural – it is why experts typically make better predictions and are payed for this.

The real power of a Bayesian approach however is not the specification of the prior, but rather the ability to update beliefs systematically based on observation, accounting for observational uncertainty. The value of observation can be seen as it allows us to reduce the space of plausible functions, constraining the posterior distribution based on the likelihood of the observations given the model. This process is often called calibration / data assimilation (model driven) or inference / learning (data driven).

Thus to reduce the uncertainty over the space of possible functions that we use to make our predictions we have two options:

1. Improve our priors (our models and associated description of uncertainties).
2. Obtain informative observations.

This is why exploration involves petroleum systems analysts and uses data. I would argue that currently petroleum systems analysis is largely an art. It often uses very complicated and detailed models based on intricate scenarios but integrates observations is a relatively ad-hoc manner with little attention to uncertainty quantification. It relies on the skill and intuition of the modeller.

To proceed to a more scientific approach we need to pay more attention to how we really use observations and models. I would argue that it is not scientific to have a complex model, based on process without having a

framework that allows you to relate this model to reality and thus observations in a consistent way. A Monte Carlo approach to risk is a start, but only a start. We need to be able to update our beliefs based on observations.

This all sounds very laudable, so why are we not using Bayesian methods in exploration? First, Bayesian methods are not easy to implement computationally. There are a range of approximations, but each has their own drawbacks. Secondly, specifying uncertainties is challenging and still debated in statistical circles, with a range of approaches, but no clear and simple dominant method. Finally, one cannot get away from the subjective nature of Bayesian reasoning. It is not possible to run the Earth system many times, so we are making judgements about a system on which we can only partially observe one experiment. We cannot easily use repeated experiments to obtain objective assessments of uncertainty. There is no truth, merely competing judgements, and that can make decision makers uncomfortable (and is why quantification of uncertainty is so important).

Chris did not call himself a Bayesian, but he cared a lot about process, rigour, risk and imagination. To progress the petroleum systems discipline we need to think more critically about what we model and how we use observations with those models, in my view within a pragmatic subjective Bayesian paradigm.

NOTES:

Petroleum Families of the Barents Sea – Paint by numbers?

Benedikt Lerch[1, 2], Dag A. Karlsen[2], Olaf Thießen[3], Kristian Backer-Owe[2]
[1]*Currently at Aker BP ASA*
[2]*University of Oslo*
[3]*Equinor ASA*

This presentation summarises geochemical results obtained during PhD and postdoctoral studies accomplished at the University of Oslo, Norway. The purpose of this work was to improve the understanding of petroleum systems in the Barents Sea by geochemical characterisation of 50 oils and condensates. In this talk, the focus will be on the evaluation of different petroleum families. Lerch et al. (2017) defined four petroleum families based on molecular and isotopic geochemical parameters, and multivariate statistical analysis: (1) Family A: Permian/Triassic sourced, (2) Family B: Carboniferous sourced, (3) Family C: Jurassic sourced, and (4) Family D: Triassic and Jurassic sourced condensates.

Age specific biomarkers, the C_{26} nordiacholestanes (Holba et al., 1996), could not confirm the presence of Cretaceous generated oils in a sample set of 50 Barents Sea petroleums. However, evaluation of the nordiacholestane ratio (NDR) on 74 shallow core samples representing the Upper Jurassic Hekkingen and Lower Cretaceous Kolje and Kolmule formations provided good correlation with literature values (Lerch et al., 2017). The majority of the Cretaceous samples showed NDR values > 0.25, while the majority of the Jurassic samples plotted with values between 0.2 and 0.25, indicating their respective ages. Biomarker and Rock Eval analysis showed that the Cretaceous intervals, in general, show a higher affinity towards terrigenous organic matter input (Type III kerogen) compared to the Upper Jurassic Hekkingen Formation, which is predominantly composed of Type II kerogen. However, one Kolje Formation interval from well 7122/2-1 showed almost similar biomarker and Rock Eval characteristics to the Hekkingen Formation, making a differentiation solely based on biomarkers quite difficult. Here, the NDR is crucial in order to differentiate possible Cretaceous sourced petroleum.

Data that were available for the PhD study made it quite challenging to differentiate Permian and Triassic petroleums. Therefore, both petroleum ages were combined and defined as Family A (Lerch et al., 2017). However, redefinition of the petroleum families is advised based on analysis conducted during the postdoctoral work. It is suggested that the oils from the Carboniferous Family B are generated from Permian source rocks, and that Family A consists of petroleum generated from Triassic source rocks. Decisive for this re-definition are oils from the 7128/4-1 well on the Finnmark Platform.

Oils from the 7128/4-1 well were considered to be of Carboniferous age (van Koeverden et al., 2010; Lerch et al., 2017), while a Permian age was suggested by Killops et al. (2014). However, positive biomarker correlation was lacking. To shed light on this controversially discussed topic, a classical oil-source rock correlation study was carried out on Palaeozoic source rocks representing the Lower Carboniferous Tettegras Formation and the Upper Permian Røye and Ørret Formations. Biomarker correlations resulted in a positive match between the Upper Permian Røye and Ørret Formations and the oils from well 7128/4-1. Hence, it was shown for the first time that the 7128/4-1 oils were generated from marine intervals of the Upper Permian Røye and Ørret Formations, and not as previously suggested from the Lower Carboniferous Tettegras Formation (Lerch et al., 2018, submitted). Evidence is based on several biomarker parameters such as the distribution of ββ steranes, and especially the distribution of tricyclic and tetracyclic terpanes.

The so far only reported Permian oil from the Barents Sea, the 7120/1-3 Gohta oil (Pedersen et al., 2017), was also included for correlation purposes. Based on the presence of gammacerane, Pedersen et al. (2017) concluded the Gohta oil to be of Permian age, as gammacerane is usually found in Permian source rocks on the Norwegian Continental Shelf. However, biomarker analysis did not reveal a positive match between the 7120/1-3 Gohta oil and Upper Permian source rocks. Yet, an almost identical biomarker fingerprint was observed in extracts from the Lower Triassic Vikinghøgda Formation on Svalbard. Due to this positive link, it is suggested that the 7120/1-3 Gohta oil was generated from an alternative Triassic source rock, that differs slightly in biomarker signatures compared to the widely distributed Steinkobbe (offshore) and Botneheia (onshore Svalbard) formations.

Based on the recent findings, a new and revised map will be presented.

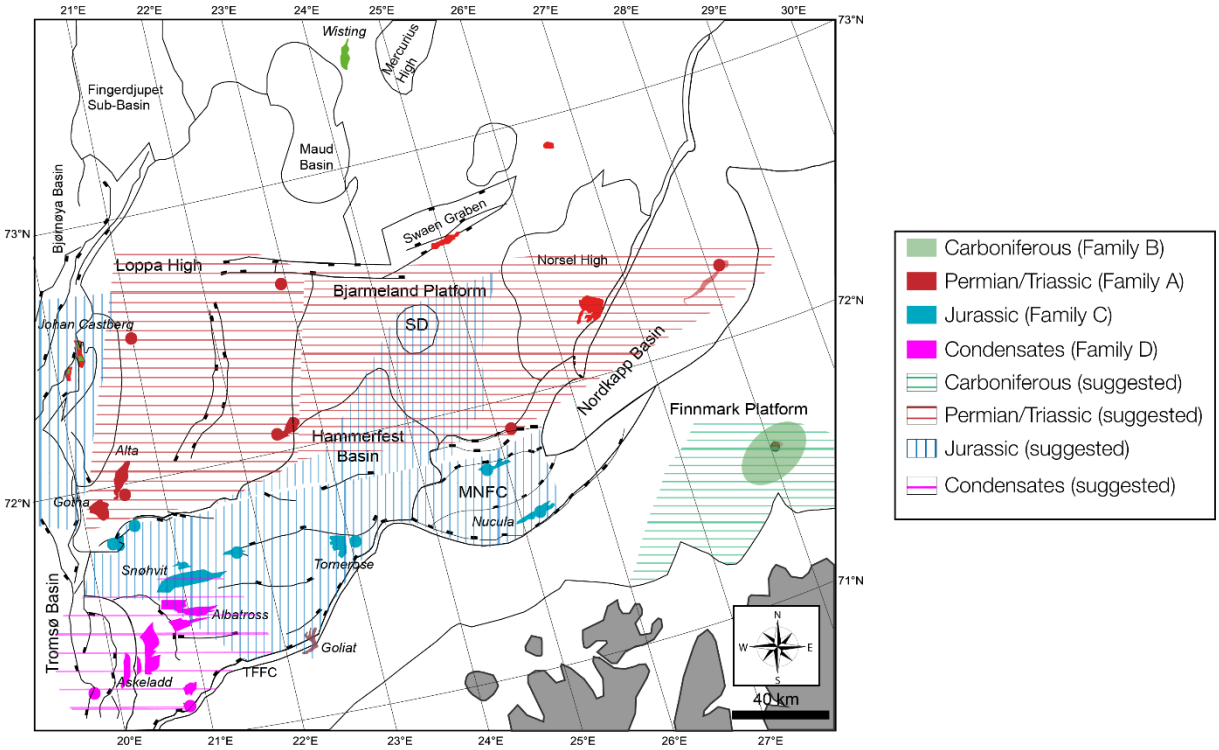

Fig.1: Map showing the distribution of the four petroleum families (Lerch et al., 2016).

NOTES:

Trends and Exceptions - Remaining Vigilant about Standard Biomarker Interpretation

Gion Kuper[1], Raingard Haberer-Kuper[1], Emma Black[1]
[1]*Tullow Oil plc.*

In the petroleum industry, the pressures on fast interpretation have often reduced the understanding of biomarker assemblages to a few basic rules of thumb which are sometimes blindly followed. For instance, finding a high relative abundance of tetracyclic polyprenoids (TPPs) in an oil sample will invariably lead to suggestions of lacustrine source contributions; high abundance of gammacerane quickly comes with a label of hypersalinity; finding oleanane will tie the sample to a young age; C_{30}-steranes definitively mark a marine source environment, and so on. These labels are quickly applied and often lasting unquestioned as the only take-away message for hastily reading general explorationists from a specialist geochemistry report. Is exploration led astray with the frequent labels of possible lacustrine source rock contributions to Atlantic oil discoveries or do biomarker data reveal hidden petroleum systems there?

In the same way that a single biomarker ratio from a sample can hardly provide a reliable interpretation without sample context and the full biomarker assemblage, the interpretation of a single sample and how it relates to a petroleum system is much enhanced by the context of a regional and global data set and by the review of general petroleum systems data and fluid properties together with the geochemistry.

Chris Cornford led the way in showing how large geochemical data sets may reveal hidden truths that would not be obvious or statistically relevant otherwise (e.g. Cornford et al., 1998). Big geochemical data sets tell us about important general trends, provide key analogues for our individual analytical data, and provide valuable insights into exceptions that may occur.

In our global data set, we show how very few of the commonly used quick biomarker interpretation labels are specific without exception and that none should be treated that way without context. Where the presence or abundance of single biomarkers in an oil sample lead to a complicated interpretation of a petroleum system, for instance invoking both marine and lacustrine source rocks contributing, the bigger data set may show that this is part of a larger trend and may yield analogues of a single source rock holding both signatures.

Big data sets reveal information that could never be reliably gathered from a single sample or well. There is therefore great value in assembling large global geochemical data sets and analysing single results in their context.

NOTES:

Linking UK, Norwegian and Danish North Sea petroleum systems – consistent oil family assignment and applications

Daniel Stoddart[1], Julian Moore[2], Lloyd Jones[2] and Steve Killops[2]
[1]*GeoEight AS*
[2]*APT AS*

The petroleum system narrative is changing as companies begin treating the UK, Norwegian and Danish North Sea sectors as 'one basin'. This is a logical step in the exploration for hydrocarbons as synergies exist enabling learnings from all sectors to enrich the development of regional charge-play models. An important element of charge play conception is oil family mapping that leads to a greater understanding of fill-spill routes and delineation of source rock contributions when combined with GDE maps. We define an oil family as a set representing a genetic oil-source rock correlation relating to a causal relationship between an oil and its mature source rock(s) that is required by the constraints of the petroleum system, which are both chemical (distinctive organic facies) and geologic (lithology, redox, subsidence rate, generation, etc) (cf. Curiale, 1994).

This paper presents methodologies aimed at assigning oil families to over 1000 oils from the UK, Norwegian and Danish sectors as well as highlighting their trends across the North Sea linking GDE maps (Figure 1). Challenges exist when correctly assigning oil families to large oil datasets often of different vintages and with sparse data of variable quality, which our methodology attempts to minimise.

The methodology employed focuses on the definition of oil families to ensure consistency of assignment and interpretation. If the methodology is accepted by the petroleum systems community it will build a foundation allowing everybody to adopt the same initial framework before branching off on bespoke pathways.

Biomarkers are used to define the oil families. A series of biomarker parameters were selected based on their applicability to separate organic matter input and depositional environment. However, the curse of the geochemist is that most biomarker ratios that are used to assign oil families are affected to some degree by thermal maturation, biodegradation and fractionation processes. Briefly, the process developed here starts with the filtering out of oils that have thermal maturities above 1.0 %Ro (calculated from MPI), have been biodegraded beyond Peters & Moldowan level 3 and show evidence of fractionation, thus ensuring that the best quality data is used. PCA is then performed on the data in order to tease out the small but significant variations in the dataset. In order to add weight to and calibrate the resulting oil family assignment, the oils were placed in the context of the work of Justwan et al., 2006. Justwan assigned 66 oils from the South Viking Graben to a set of oil families based on a series of biomarker parameters. The South Viking Graben oils dataset provide a good laboratory for oil family assignment as source rocks ranging from Draupne Fm to Heather Fm and Middle Jurassic have contributed hydrocarbons to discoveries in the area and encompasses varying contributions of marine and terrestrial kerogen as well as degrees of oxygenation during deposition.

Methodologies assigning oil families to sparse biomarker datasets will be highlighted.
Data demonstrating that six main oil families can be identified and, although it is recognised that oil family mixtures and organic facies variations within source rock units may influence oil family assignment, it is considered that this methodology provides a workable interpretation of the data that can be refined further by incorporation of additional diverse datasets.

The distribution of the oil families throughout the UK, Norwegian and Danish sectors will be presented in the context of Upper Jurassic and Palaeocene GDE maps.
This work goes a long way to providing a much needed first order standardisation of oil family assignments throughout the North Sea enabling petroleum systems analysts and exploration geologists alike to 'speak the same language' when talking about fill-spill routes and delineation of possible source rock contributions. The data provide a calibrated regional approach to charge-play fairway mapping.

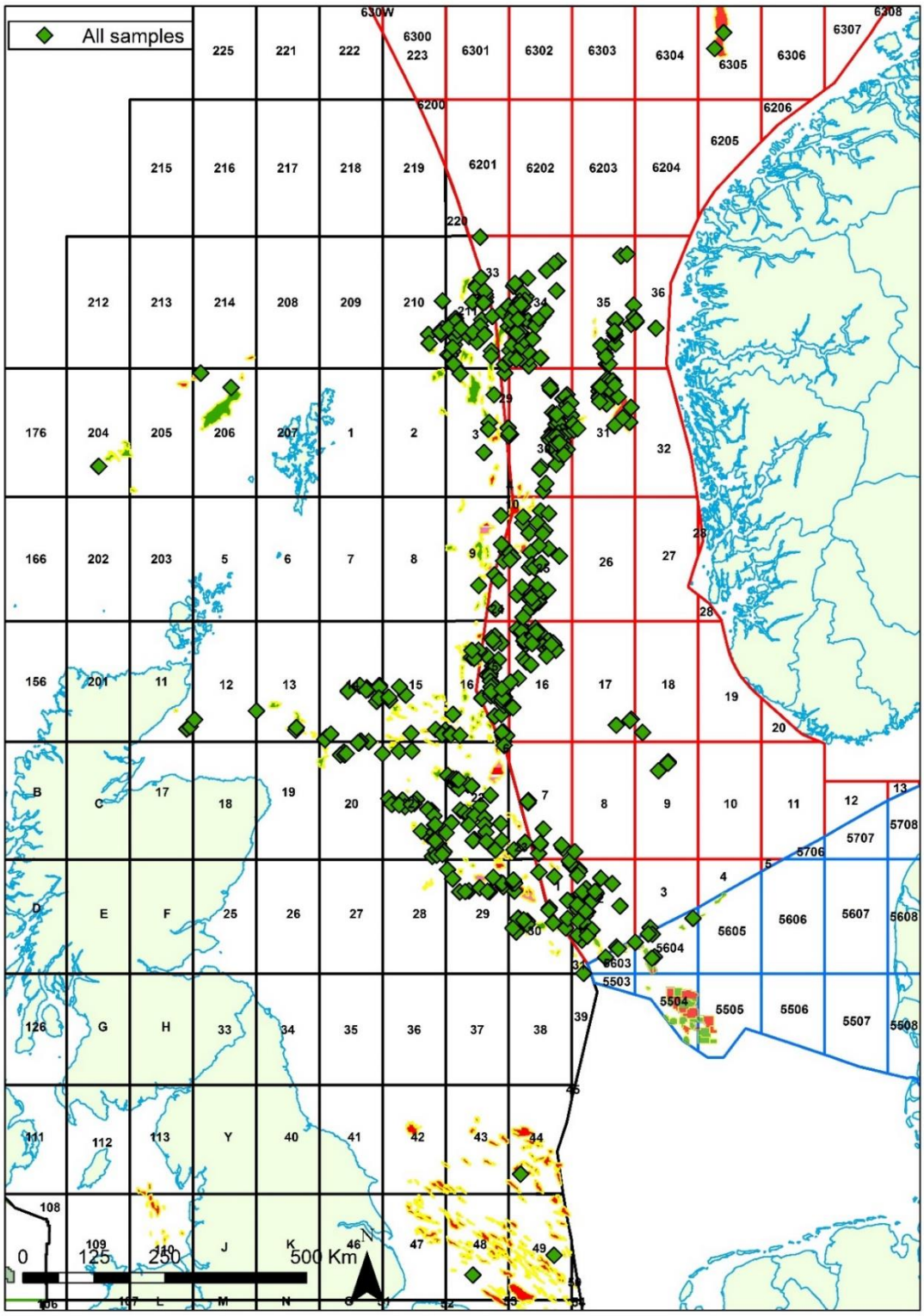

Figure 1 showing the location of the samples used in the study from UK, Norwegian and Danish offshore sectors.

NOTES:

Maturation & migration – Fundamental petroleum system processes unravelled using the high molecular weight NSO fraction

Volker Ziegs[1], Mareike Noah[1], Stefanie Poetz[1], Brian Horsfield[1,2]

[1] *GFZ German Research Centre for Geosciences*
[2] *GEOS4 GmbH*

The well-explored North Sea Central Graben contains a great many petroleum accumulations that have been charged from Upper Jurassic marine shales. Using a large data base containing ~2,000 Rock-Eval data sets**, both source rocks in that basin, the Mandal and Farsund Formations, were identified as being inefficient or late expellers, retaining substantial amounts of their volatile products. Mass balance calculations, taking variable initial generative potentials of the Mandal Formation into account, indicate a broad variance of high and low retention capacities at maturity levels lower than peak oil. This is a quite untypical behaviour as compared to e.g. the Viking Graben source rocks. Thus, some expelled oils are expected to be of elevated maturity while others are less mature. This study seeks to determine if the special situation in the Central Graben affects the composition of crude oils, i.e. as crude oils in different reservoir lithologies follow different depth gradients (Fig. 1a). 24 source rock samples representing two maturity series with different starting potentials were selected for molecular characterisation studies, as was a suite of 24 oils representing a variety of maturity stages from different regions and reservoir lithologies in the Central Graben.

Using conventional GC-FID and GC-MS approaches on the saturate hydrocarbon fraction, the provenance of crude oils has been proven to be of marine origin with varying water column oxygenation levels exceeding the maturity indication of sterane ratios being mature to overmature (according to the hopane ratios Ts/Tm and 29Ts/NH).

The medium- to high molecular weight NSO fraction contains an abundance of geochemical information. Additionally to maturity and facies, migration effects (Koch et al. 2005; Mahlstedt et al. 2016; Oldenburg et al. 2014; Poetz et al. 2014; Rocha et al. 2018; Ziegs et al. 2018) can be unmingled by identifying heteroaromatic compounds and assessing their aromaticity, molecular size and polarity using ultra-high resolving FT-ICR-MS. While the relative distribution of different types of NSO compounds varies according to depositional environment, their degree of cyclization and aromatization, i.e. that of carbazolic and phenolic species identified using the (-) ESI mode, indicates maturity differences (Oldenburg et al. 2014; Poetz et al. 2014) and correlates with hydrocarbon biomarker ratios (Ziegs et al. 2018). Aliphatic chain length distributions (Fig. 1b) are generally varying as a function of maturity. More mature North Sea Central Graben oils trapped in sandstone reservoirs that are directly adjacent to potential source rocks are dominated by carbazole homologues with shorter side chains. However, in case of the oils trapped in carbonate reservoirs, the chain length distribution is strongly influenced by expulsion (Mahlstedt et al. 2016) and migration distance (Ziegs et al. 2018). We infer from physical properties of polar compounds with shorter chains that these interact more intensively with a polar environment such as initial formation water, crystal water in clay minerals of source and carrier rocks or faults as well as mineral surfaces or residual organic matter in the source rock. A removal of high molecular weight compounds from the migrating fluid phase as a function of migration distance significantly alters its physical properties affecting migration and production behaviour of crude oils.

** Aker BP is greatly acknowledged for having founded this study and provided the data.

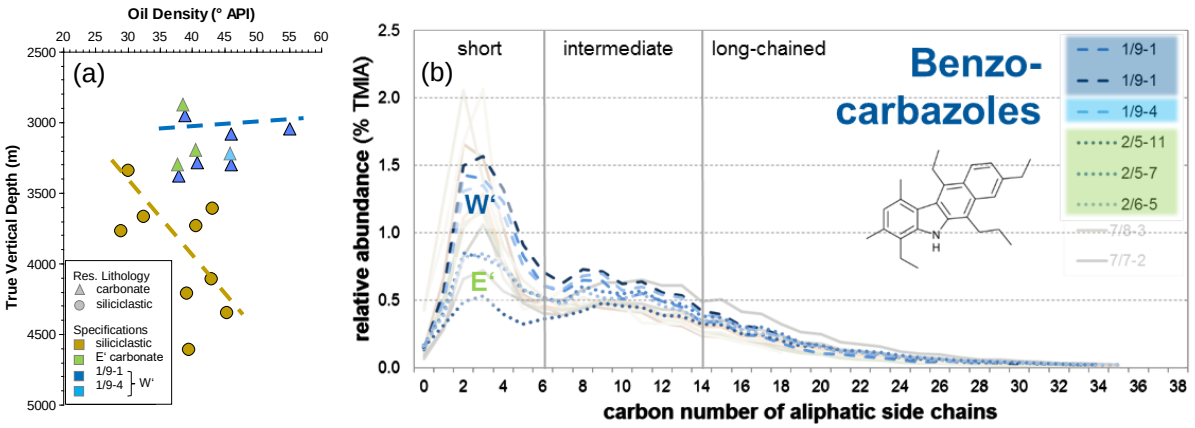

Fig. 1. The API-depth plot of 16 crude oils along the Central graben shows different gradients for oils in clastic (pale colours) and carbonate (blueish colours) reservoirs with the former following a maturity trend. Based on depth distributions, oils in carbonate reservoirs might have experienced longer migration than those in clastic horizons adjacent to Upper Jurassic source rocks. Respective chain length distributions (CLD) of aliphatic carbon atoms attached to benzocarbazole core structures as measured using ultra-high resolving FT-ICR-MS in (-) ESI mode illustrates that CLDs of oil constituents in carbonate reservoirs might be influenced by migration distance while CLDs of oil constituents in clastic reservoirs are solely controlled by maturity.

NOTES:

Session Two: using data to inform Petroleum Systems Analysis

KEYNOTE: Top Down Petroleum System Analysis and Geospatial Patterns of Petroleum phase and Properties

Zhiyong He[1], Andrew Murray[2]
[1]*ZetaWare, Inc.*
[2]*Murray Partners PPSA Pty. Ltd.*

The fluid-phase and bulk properties of petroleum fluids are controlled by the source rock organofacies, maturation, expulsion fractionation, pressure and temperature along migration pathway and in the traps. Together with the basin geometry and stratigraphy, these factors dictate the spatial distribution of oil and gas. "Top-down" petroleum systems analysis is the interpretation of the distribution and properties of fluids, including gas-oil-ratios, gravity and composition, along with shows, seeps, dry holes, and other relevant well data in the geo-spatial and PVT 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" from well explored basins, especially the copious production data from unconventionals, and data analytics tools with geospatial capabilities 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. Normally 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, the fluid phase (oil or gas) found in the trap depends on whether the trap leaks or spills. High GOR (volatile) oils or rich condensate gas can only exist as a single phase in deep reservoirs due to their high saturation pressure.

Based on the understanding of such controls, and the observation of fluid phase properties and their distribution, we can interpret source rock organo-facies, dominant migration process and trends in fluid phase, and predict likely or possible fluid type in prospects based on location, depth, and trap closures.

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.

NOTES:

A combined Geochemical and Phase Equilibrium approach to Petroleum Migration

Mike Fawcett and **Brian Moffatt,**
Petrophase Ltd

In the Exploration and Production industry we view technical challenges through the lens of our home discipline; we deem biomarkers lie in the domain of geochemistry while oil properties and reserves estimation belong to petroleum engineering. However Mother Nature sprinkles her clues indiscriminately across all disciplines so many technical problems refuse to sit neatly in a single domain, indeed the expertise from several may be needed to understand the placement and properties of petroleum.

A fascinating case study requiring inputs from several disciplines is presented. A single well intersected 20 different zones of different compositions and formation sampling tools recovered samples with varying degree of mud contamination. The operator was unsure of how representative the decontaminated samples were and the relationship between the different zones. What was the story of the varied fluids?

Figure 1, The solidifying 14 API oil

The deepest zone contained a near critical rich gas condensate above which lay a 14 API heavy oil with an exceptionally high bubble point, nearly 11,000 psia. Stacked above this heavy oil lay several different condensates. The problem was to assess the quality and nature of the fluids. Geochemical and isotopic analysis discounted biodegradation and confirmed only two charges; an oil and a late mature gas.

The generation of this wide range of fluid types was accurately modelled using phase equilibrium calculations. It was found that a local oil plus gas became two-phase under the reservoir conditions. The addition of a late mature gas phase stripped out intermediate components from the oil. The modelling of successive gas stripping steps modified the initial oil composition until it gave a remarkable match to the observed 14o API oil (Figure 2).

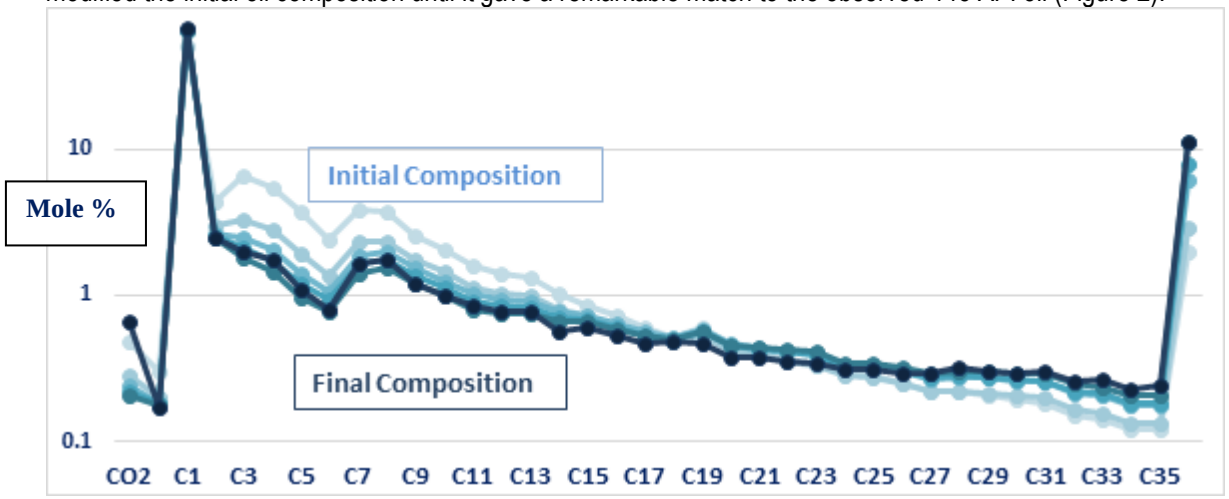

Figure 2, Evolution of the heavy oil by gas stripping

The compositions of the upper interval lean condensates were found to closely match the composition of a dry mature gas enriched by intermediate components from the regional oil.

The deeper condensate reservoir was at a pressure high enough such that the local oil had first contact miscibility with the secondary gas charge. The condensate fluid composition was found to be a simple arithmetic combination of the local oil composition and the late mature gas (Figure 3).

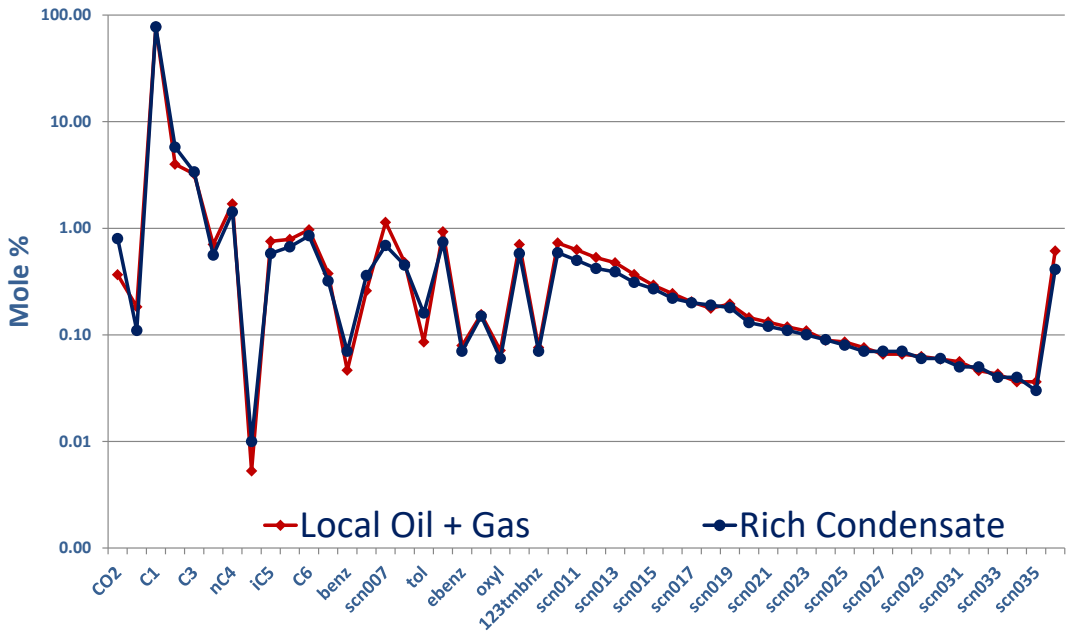

Figure 3, Comparison of discovery Rich Condensate composition (blue) and combined local oil with late mature gas (red).

The project could not have worked using geochemistry alone nor phase behaviour alone. The combination of both unlocked the secrets to understand the petroleum migration and gave a basis for calculations of recovery of oil and gas for sales predictions which is normally independently calculated from PVT studies. In the final assessment all pieces of information fitted together to give a single coherent story which spanned across Geochemistry, Phase Behaviour, Geology and Petrophysics.

Success was better achieved through acting as a Petroleum Detective than from a single named discipline.

NOTES:

The Seco-oleananes: Identification, Origin and Distribution in Late Cretaceous/Tertiary Deltaic Petroleum Systems

Olukayode J. Samuel[1], Geir Kildahl-Andersen[2], Jon Eigill Johansenb Hans Peter Nytoft[3]

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The recognition of certain molecular compounds that represent specific processes and products in time and space over varying bio-chemical conditions in the geosphere and their successful linkage to their natural products in the biosphere has permitted the use of compounds like oleanane, lupane, gammacerane and bicadinanes in characterizing sedimentary organic matter and petroleum. Four novel seco-oleananes (A1, A2, B1 and B2) and a compound "C" previously identified as seco-hopane can be detected in crude oils containing oleanane from all parts of the world. While the novel seco-oleananes are absent in oils with no oleanane, compound "C" is present in both non-oleanane containing oil from North Sea and deltaic oil samples, irrespective of the organic matter source and age of the source rock.

Like 8,14-seco-hopanes, the seco-oleananes are best monitored free from interfering peaks in the m/z 123 and m/z 414 mass chromatograms or using the m/z 414 → 123 and/or 414 → 399 transitions. B2 and A2, the two most abundant of these compounds, were isolated using HPLC and assigned as 18□(H)-8,14-seco-oleanane and 18□(H)-8,14-seco-oleanane, respectively, using NMR spectroscopy. The NMR data support structures for B2 and A2 in which both CH3-26 and CH3-27 have an equatorial configuration, in contrast to the axial configuration in the typical oleanoid precursors. There is a correspondence between the C-Index (A1+A2+B1+B2/C) and the level of angiosperm land plant inputs into organic matter content of crude oils from Late Cretaceous-Tertiary deltaic basins, thus permitting the use of C-Index in discriminating organofacies among oils and in oil-source rock correlation studies. There is absence of thermal maturity influence on the C-Index. Seco-oleanane B2 was successfully synthesized under laboratory condition of isomerisation and hydrogenation of oleanenes mixture from pure lup-20(29)-ene prepared from birch-bark. This observation suggests that the natural B2 in oil was probably formed under conditions of isomerization and hydrogenation of either acid catalysed ring-C opened pentacyclic product of oleanenes or a tetracyclic compound derived from angiosperm higher plant precursors.

NOTES:

Artificial-Intelligence assisted hydrocarbon exploration: Case examples from the Norwegian Continental Shelf

Daniel Austin, Eirik Larsen, Steve Purves, Arne Klepp Kvalheim, Jean Baptiste Bonas.
Earth Science Analytics AS

Exploration history shows that predicting the spatial and temporal distribution of hydrocarbons is hard, although as explorationists we have long recognized that some stratigraphic and structural trends are more hydrocarbon prone than others. We know this because of the vast volumes of seismic, well and production data acquired over many decades. The knowledge explorationists have derived from all this data, through collaboration and integration in multidisciplinary teams, have nevertheless driven historical exploration success. Technological advances in geophysical data acquisition and processing (in particular 3D seismic, AVO and CSEM) have spawned several waves of exploration, and delivered discoveries in areas where these technologies provide sufficient reliability. The ever-increasing volume and modality of subsurface data are exposing exploration geoscientists and managers to a formidable challenge; how to extract the right intelligence from the data, and how to use this to make better predictions. We argue that these large and diverse subsurface datasets are underutilized due to the lack of methods with which to handle such large amounts of data. This calls for entirely new methods of knowledge extraction and data driven predictive analytics.

We are now, in the midst of the data-science renaissance. It is therefore timely to consider how we can leverage modern data driven predictive analytics and artificial intelligence to enhance our understanding of the distribution of hydrocarbons in time and space. In this talk we will discuss; i) what we can predict today using Artificial Intelligence (AI), ii) what new insights we can gain, and iii) how this technology can be used in our efforts to improve hydrocarbon exploration success. We review the application of data analytics methods and artificial intelligence on case examples from the Norwegian Continental Shelf, on both regional and prospect level scales.

AI, and more specifically machine-learning (ML) is now being used, across multiple domains to reveal hidden relationships in data and to predict properties as multidimensional and nonlinear functions of measured data. The technology mitigates human biases through models derived directly from data, whose accuracy is measured by blind testing against the data itself.

So, how does ML work, and what can these models learn directly from the data we use in hydrocarbon exploration? ML can be used; i) to identify inherent structure in data using cluster analysis (unsupervised learning) and ii) to learn transfer functions that maps an input to an output based on many examples of input-output pairs (supervised learning) iii) learn to model complex phenomena and create new examples of them (generative learning). Unsupervised learning has long been familiar to geoscientist; petrophysicists use such methods amongst others in electrofacies analysis while geophysicists use them for multi attribute analysis. Supervised learning also has a long track record in geoscience; using well data to infer lithology, porosity and other properties from wireline logs or segmenting seismic facies from 3D volumes. However, the variety, sophistication and power of these approaches have grown significantly alongside maturing or approaches such as generative learning that are wholly new to geosciences. During the last three decades, researchers have used well data for training neural networks such as multi-layer perceptron's to infer lithology, sedimentary facies, porosity, and fluid saturation as functions of wireline logs. During the last few years, researchers have demonstrated that deep neural networks can be used to segment facies in seismic volumes in order to identify geobodies like salt, channels and faults. These methods, and others which we will illustrate, are transforming subsurface workflows across many sub disciplines of petroleum geoscience.

We present results from both regional and local studies where we have used a wide array of ML models and data science practice to characterize the subsurface.

On a regional scale, we have trained supervised ML models with well log data as features and core data or petrophysical models as target labels. We have conditioned wireline logs across several hundred wells in order to enable prediction of rock and fluid properties across the entire drilled stratigraphy where we have measured prediction accuracies for using a cross-validation approach with blind testing against all wells in the dataset. The

data-types we have predicted in the well data set includes porosity, permeability, lithology, sedimentary facies, source rock properties, and fluid saturation among others.

On a local scale, we have trained supervised ML models with seismic full and partial stack volumes as features and rock and fluid properties from wells as target labels. This data was fed to deep convolutional neural networks which were used to predict rock and fluid property volumes based on up-scaled versions of the inferred property logs. Wells within the 3D seismic survey boundaries were used in blind test cross validation training schemes, allowing network hyperparameters to be tuned and model performance to be assessed.

In order to provide stratigraphic and structural context to the predicted rock and fluid properties, we have used automated seismic interpretation techniques to map stratigraphic units and faults from seismic data. We used fully convolutional deep networks for fault interpretation and deep encoder-decoder networks such as SegNet for stratigraphic interpretation. These techniques classify 3D seismic post-stack datasets based on either 3D subcubes or 2D sections, achieving a high level of consistency based on a relatively small number of expert labelled regions.

Since geological interpretation and prediction is typically based on sparse and low-resolution data and is inherently uncertain, we apply methods such as Bayesian neural networks to determine model uncertainty for automatic seismic interpretation. We efficiently integrate scenario analysis with ML modelling to construct multiple models based on variations of the input data. In addition to applying a data driven approach, we have also an opportunity to include uncertainty analysis as an integral and fundamental part of everything we do.

ML models work remarkably well when large, structured and labelled data sets are available for training. The incredibly rich subsurface data and metadata available in national data repositories and company databases are starting to be conditioned to serve as rich resources for training machine-learning models at scale. When we can use machine-learning technology to build models at scale from well and seismic data, we can start to piece together the data-driven puzzle needed to define and characterize known and potential hydrocarbon accumulations. We can now begin; i) to leverage machine learning in play screening, using all the available log and core data, ii) apply machine learning models to reveal missed pay intervals, which frequently have been the inception of successful discoveries, and iii) to identify and characterize prospects, discoveries and fields. These tasks typically require use of multiple ML models applied to multiple data types, and technology that enables true data-driven integration.

The application of ML technology to subsurface prediction tasks shows that integrated and interdisciplinary approaches leads to a deeper understanding of the subsurface and provides a framework for creative solutions and improved decision-making. The future for decision-making technology for exploration and production is here, today, and we should integrate this technology into our workflows to enable data driven and cost-effective decisions. This technology is available; it is being used today and it is not solely a technology of the future, and because of this, workflow efficiency is now being improved by orders of magnitude. Prediction accuracy is exceeding that of traditional "best practice", today. Imagine what it will be like tomorrow when really large data sets are available for training models.

NOTES:

Charge history of the Snefrid Nord gas and oil discovery – A collage

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[1]*Equinor ASA – Exploration*
[2]*IFP School, Paris, France, now at Equinor ASA*

The 2015 oil and gas discovery in well 6706/12-2 (Snefrid Nord) in the Norwegian Sea deep water has triggered renewed interest in the understanding of the petroleum system in the Møre-Vøring basins. A bimodal distribution of 50% methane vs 50% C10+ leaves plenty of scope for interpretation with respect to the charge history.

The gas range hydrocarbon interpretation has to be performed on stable carbon and hydrogen isotopes of methane as ethane to butane range hydrocarbons are present in too low concentrations. Applying standard interpretation schemes the gas range hc seem to be of thermogenic origin from a mixed/marine terrestrial source rock of early to peak oil maturity. The dry character of the fluid could point to the presence of a migration fractionated oil associated gas or a mixture of high mature coal derived gas with microbial gas.

Reservoir temperatures significantly below 80°C led to a near complete degradation of the gasoline range hydrocarbons. A huge unresolved carbon complex mixture between n-C10 and n-C32 defines the envelope of the heavier oil components. However, sterane biomarker analysis give to some degree an interpretational response and age specific biomarker point to a Cretaceous or Cenozoic origin at least of the oil range hydrocarbons.

Core extracts from the gas column seem to be chemically related to the oil leg while asphaltene concentration decreases from the top of the hydrocarbon column to the base.

Several source rock layers of Jurassic, Cretaceous and Cenozoic age are discussed to be present in the Norwegian Sea deep water (e.g. Brekke et al., 1999, Øygard and Olsen, 2002; Garner et al. 2017), some of them are proven. Conventional basin modeling results illustrate that Jurassic source rocks might be a source for thermogenic dry gas while Aptian source rocks might contribute with some additional wet gas. Cenomanian/Turonian shales which also have reached the gas generation window may contribute with some light oil if re-migration is considered. Santonian shales are in the right position with respect to oil generation but most likely are not enriched enough with organic matter. A potential Cenozoic source rock, if present, would have reached the oil window to the north of the discovery.

Microbial gas generation modeling has shown that sedimentation and subsidence rates in the Vigrid and Någrind synclines during the Santonian to Campanian have been high enough to constantly generate microbial gas during post-Turonian times.

Considering all observations, one can compose a complex picture illustrating the charge history of the Snefrid Nord structure. It is now about the scientist/artist to set the single fragments into the right order.

NOTES:

Source rock from seismic (SRfS) – from rock properties to basin distribution

Marita Gading, Lars Wensaas, Helge Løseth
Equinor ASA

The ability to identify a source rock in the subsurface and quantify its parameters has a significant impact on prospect risking assessment of a petroleum play. Traditionally, the risking is based on geochemical analyses of hydrocarbons or source rock samples. Here we present a methodology for identifying, characterizing and mapping the spatial distribution and quality of thick source rock intervals based on seismic data termed Source Rock from Seismic (SRfS). This proprietary method has been used on datasets worldwide with success over a number of years.

In our study the relationship between organic content and rock properties of shale source rocks has been studied in fully cored scientific boreholes and in numerous exploration wells. The borehole datasets include a fully cored section of the Upper Jurassic Kimmeridge Clay Formation in Dorset, with conventional wire line logs and a very extensive analytical programme on core samples. These datasets are used to establish relationships between total organic carbon (TOC) content and acoustic properties, which can be obtained from seismic data. The results show that bulk density (Rhob) is linearly reduced, while the compression velocity (Vp) is non-linearly reduced with increasing organic content. Consequently, acoustic impedance (AI) is reduced non-linearly with increasing richness. Acoustic impedance is very sensitive to even small increases in organic richness and is clearly lower than the surrounding leaner shales at all depths.

Forward modelling of reflectivity (isotropic conditions) and amplitude versus offset (AVO) behaviour suggests that top of source rock intervals is associated with a drop in impedance that produces a negative reflection coefficient or a 'soft' response. This negative normal incident reflection decreases from near to far offset (AVO class 4 response), which is proven a very robust criterion for source rock identification on seismic data. The base of the source rock interval is characterized by an increase in impedance and dimming of positive amplitude with offset. Impedance decreases (non-linearly) with organic richness and therefore the top source rock amplitudes become stronger with increasing organic richness. Organic-rich shales have also strong intrinsic velocity anisotropy at all scales and the velocity anisotropy increases with organic richness. Seismic responses at the top and base of source rock intervals also depend upon factors such as layer thickness and vertical layer stacking variations in richness (organic profiles).

SRfS has been used to identify and map out source rock thickness and richness on seismic data in many sedimentary basins.

NOTES:

Session Three: Petroleum Syststems Analysis – State of the Art

KEYNOTE: The Witswatersrand (Wits) Basin Gold-Uranium Mineralisation – Freeze-frame on an Archaean Petroleum system

Andy Barnicoat[1] , Abhen Pather
[1]*Geoscience Australia*
[2]*RPS Energy*

A petroleum system associated with gold-uranium mineralisation in the Archaean Wits Basin of South Africa provides a rare view of a 'frozen-in' petroleum system. Despite its apparent uniqueness the processes involved can be considered 'normal' basin processes. However the level of complexity of the system required an integrated study by a range of scientific disciplines.

Gold grains are directly associated with carbon in the form of stratiform seams and so-called 'flyspeck'. Microscopic observations led by Chris Cornford showed that the carbon is pyrobitumen with a 'mesophase' structure and therefore constitutes hydrocarbons altered by the action of short-term heating and not in-situ algal material as previously believed. The demonstration that the carbon was a migrated hydrocarbon showed that the gold must be secondary (epigenetic) and that we are dealing with a petroleum system (familiar ground for petroleum geologists). The carbon turned out to be the 'Rosetta Stone' of the mineralisation.

Organic geochemistry, petrography and basin modelling indicate that Archaean black shales in the Wits basin are likely source rocks that generated the hydrocarbons associated with gold mineralisation. These now post-mature black shales contain less than one percent total organic content (TOC) but would have been organically richer at the time of deposition. Given that these source rocks are Archean and marine the organic composition would have been exclusively Type II oil-prone kerogens. Also all would have been anoxic due to the low-level or absence of atmospheric oxygen at the time. Burial history modelling was undertaken based on an asymmetrical foreland basin architecture on a thick stable Archaean continental crust characterised by low heat flows (Beach & Smith, 2007). Modelling results indicate good potential for oil and gas generation, and adequate charge potential, from intra-basin kitchen areas during syn- and post-Wits times.

Regional and local structural analysis combined with petrographic work clearly identifies syn-Wits thrusting, the development of linked fracture systems and extensive phyllosilicate alteration. The remnant, 'frozen' hydrocarbons occupy fractures which evidently formed an important part of the plumbing system (Jolley et al. 2004).

The carbon mesophase structure, hydrothermal alteration assemblages and gold mineralisation shows that the hydrocarbons interacted in the fracture network with gold-bearing 'hot' fluids (>200C°) during syn-Wits thrusting (Barnicoat et al., 1997). Inorganic geochemical modelling shows that these were probably extra-basinal fluids and modelling of organic thermal alteration levels (hydrothermal-hydrocarbon interaction) determined from bitumen reflectance has allowed estimation of temperatures and fluid flow duration and timing (Gray et al., 1998).

The petroleum system integral to the development of Wits gold mineralisation (the world's largest gold-forming mineral system) demonstrates the importance of understanding the entire geological system, a key tenet of Chris's philosophy. In the Wits, this complexity is more visible due to the arrested development ('freezing') of the system. That such complexity is perhaps relatively common is demonstrated in the Phanerozoic sediments of Nevada where producing oilfields and Carlin-type hydrocarbon-associated gold mineralisation occur in close proximity.

NOTES:

Using magnetic techniques to calibrate lateral hydrocarbon migration in basin modelling: A Case Study from the Lower Tertiary, UK Central North Sea

S. Adesope Badejo[1], Adrian Muxworthy[1], Alastair Fraser[1] and Martin Neumaier[1]
[1]*Imperial College London*

Pyrolysis experiments show that magnetic minerals can be produced inorganically during oil formation in the 'oil-kitchen'. Here we apply a novel use of this observation to identify a magnetic proxy that can be used to trace hydrocarbon migration pathways by determining the morphology, abundance, mineralogy and size of the magnetic minerals present in reservoirs. We address this by examining the Tay formation in the Western Graben in the Central North Sea.

Basin modelling has been carried out in the Tay sandstone in the North Sea which is well constrained by borehole and 3D seismic data. This allows us to clearly demonstrate initial vertical migration from a mature Jurassic (Kimmeridge Clay) source in the Central Graben to the east into overlying Tertiary sandstones of the Tay formation. Lateral migration updip to the west through the Tay channel system is also predicted by the model. Increasing oil gravity along the fill spill chain appears consistent with this interpretation. Importantly, the Jurassic source rock is shown to be immature over the majority of west and central study area, requiring lateral migration as the charge mechanism for the existing Tertiary fields.

The magnetic properties of core samples from the study area were determined using room-temperature measurements on a Vibrating Sample Magnetometer (VSM), low-temperature (0-300K) measurements on a Magnetic Property Measurement System (MPMS) and high-temperature (300-973K) measurements on a Kappabridge susceptibility meter. Magnetite, pyrrhotite, pyrite and siderite were observed in the samples. An increasing presence of ferrimagnetic iron sulphides is recorded along the known hydrocarbon migration pathway.

Our initial results suggest mineralogy coupled with changes in grain size are possible proxies for hydrocarbon migration and importantly show trends matching the petroleum systems model. Importantly the magnetic signatures have required changes to the geological input to the basin model resulting in an improved petroleum systems model.

NOTES:

Development of a stratigraphic framework for the distal domain of the Mauritania-Senegal-Guinea-Bissau-Conarky Basin (MSGBC), NW Africa Atlantic passive margin

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Oceanic volcanic islands in passive margin basins offer the opportunity to examine at outcrop, deep sea sediments that are otherwise only penetrated by the drill bit and/or imaged using seismic reflection techniques. These islands allow a comprehensive analysis of deep-water stratigraphy; where a stratigraphic framework can be developed in the distal domain and post-rift stratigraphy fully examined using conventional fieldwork and ensuing laboratory analysis.

The island of Maio, one of nine islands in the Cape Verde Archipelago is unique to the Central Atlantic as the island has exposures of ophiolites and overlying Mesozoic deep water stratigraphy uplifted during the Cenozoic. This provides the opportunity to assess paleo-environments of the early Central Atlantic and contribute towards the knowledge of passive margin evolution in the proven oil and gas province of the Mauritania-Senegal-Guinea-Bissau-Conarky Basin (MSGBC) basin. Findings can be integrated with new multi-disciplinary analysis of Deep Sea Drilling Project (DSDP) Leg 41 results to understand the petroleum systems of this emerging basin.

This stratigraphic analysis aims to refine the stratigraphic scheme developed by geologists, palaeontologists and stratigraphers on Maio since the early 20th century (see Fourcade et al., 1990 & references therein). The first collection of ammonites from the lower sedimentary succession, bed-by-bed sampling and micro-palaeontological analysis, combined with a re-interpretation of the complete palaeontological collection by Stahlecker (1934) provides a comprehensive dataset to build a high resolution stratigraphic framework and clear uncertainties surrounding the dating of the Mesozoic stratigraphy of Maio. Combined with a new biostratigraphy, sedimentology and organic geochemistry study of the DSDP sites inboard of Maio, we propose a revised stratigraphic framework that can be correlated inboard using regional 2D seismic surveys.

The new stratigraphic framework is used with industry well and DSDP geochemistry data to identify and extrapolate organic-rich intervals as potential source rocks across the basin. It has also allowed a relative evaluation of the source potential of OAE developments within the greater organic-rich intervals.

NOTES:

Calculated radioactive heat production in the North Sea: new data for petroleum systems analysis

Alexander Finlay
Chemostrat

Petroleum systems analysis has many uncertainties, one of which being the radioactive heat production from the lithosphere, basement and sedimentary lithologies. Radioactive heat is predominantly generated by the radiogenic decay of isotopes of Potassium (40K), Thorium (232Th) and Uranium (238U & 235U), so it is therefore possible to model radioactive heat wherever these geochemical data are available. Radioactive heat production values of North Sea upper crust are commonly cited in most software as 2.8 µW/m3, representing "typical" Caledonian basement. However, the variability of Caledonian radioactive heat production as well as the contribution from overlying sediment in the North Sea is poorly understood. This is important as a variation in radioactive heat production of ~1 µW/m3 has been shown to have a major implication on petroleum systems models. For example, Finlay et al. (2018) demonstrated that the Lewisian basement in the West of Shetland Basin possesses much lower radioactive heat values (typically between ~0.8 – 1.8 µW/m3) and when these values were used, the produced model calibrated favourably to both vitrine reflectance and Horner Corrected bottom hole temperatures in well 204/10-1 (Cambo-1). Furthermore, this lead to a delay in oil expulsion from the Kimmeridge Clay Formation source rock of ca.10 – 25 Ma in 1-D pseudowell models in the Flett and Gudrun Sub-basins, removing the need for a motel reservoir migration model and associated hydrocarbon loss as previously suggested by Lamers & Carmichael (1999).

This paper, builds on the West of Shetland work of Finlay et al. (2018) by modelling radioactive heat production in the North Sea. This will be undertaken through the calculation of radioactive heat production from published and Chemostrat multiclient geochemical data covering a range of Caledonian basement as well as Devonian to Paleocene sedimentary units. In addition different published models for calculating radioactive heat production will be compared (e.g. Turcotte and Schubert, 2014; Rybach, 1988) as will the effects of rock density.

NOTES:

The unconventional hydrocarbon potential of the Weald Basin, onshore UK. A 3D basin and petroleum system modelling approach

Francesco Palci[1], Alastair Fraser[1], Martin Carles[1], Martin Neumaier[1], Fatima Al Kabah[1], Stephen Sanderson[2], Rob Wallace[2], Jamie Burford[2]
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[2] *UKOG*

The Weald Basin has a long history of hydrocarbon exploration commencing over 60 years ago. The exploration activity was initially focused on the prominent anticline structures identified by surface geological mapping and supported by the several oil seepages along the Dorset coast. During the 1970's, the application of reflection seismic technology allowed the imaging of subsurface tilted fault blocks resulting in the discovery of 13 small to moderate-sized conventional oil and gas fields. Hydrocarbons are produced from conventional sandstone and carbonate reservoirs, sourced from Jurassic marine shale. These source rocks include the Kimmeridge Clay, the Oxford Clay and the Liassic Clay intervals. This conventional view of the Weald Basin potential changed drastically in 2014 following the Horse Hill-1 oil discovery near Gatwick. The borehole tested significant hydrocarbons from two tight fractured micritic limestone layers interbedded with the Kimmeridge Clay, unlocking a new hybrid play within the Weald Basin.

In this study, 2D seismic and well data were used to build a high-resolution 3D model of the subsurface which takes into account both the stratigraphic architecture of the basin and its structural complexity. The micritic limestone layers were modelled and populated with facies and petrophysical properties tied directly to well data. Total organic carbon estimates of the Kimmeridge and Oxford clays were generated using well log data calibrated by geochemical analyses of core and cuttings data. The 3D model was simulated using basin and petroleum system software. The resulting 3D dynamic model allowed the amount of burial and uplift experienced by the basin to be quantified providing improved constraints on the thermal maturity, the timing of hydrocarbon generation and migration in the basin.

The results have demonstrated that significant volumes of oil are present in the Kimmeridge micrite play in the central Weald. The key question remaining to be addressed is the amount of oil that can ultimately be recovered from the play.

NOTES:

Session Four:
Thermal History Reconstruction in petroleum systems analysis

KEYNOTE: Thermal History Data and Missing Section - The Great Uplift Debate gets into Deep Water

Richard Bray & Steve Lawrence,
Subsurface Resource Consulting

'The Great Uplift Controversy'
'Among the subjects which have for some years past engaged the thoughts of geologists, none perhaps has excited so general and intense an interest as the Theory of Elevation' - George Bellas Greenough, Geological Society Meeting 1834.

In the early to mid-1800's a great debate raged over the true meaning of unconformities as recognised by Hutton, Smith and others. This was a key time in the history of geology with the realisation that not all geological time is represented in the preserved stratigraphic record.

In the late 1980/90's another debate followed the publication of thermal history data around Britain interpreted in terms of km-scale uplift and erosion during the Late Cretaceous and Tertiary. Since then the body of evidence is become overwhelming that Britain and other continental margins have been uplifted during the 'passive' post-rift stage of basin development.

The 'Science' of Thermal History Reconstruction (THR)
THR is a scientific technique based on data measured directly from rock samples giving information on the temperature-time history. THR goes back to the 1970's, where vitrinite reflectance (VR) profiles were used to estimate the amount of uplift at unconformities. It received a significant boost with advent of kerogen kinetics, enabling VR to be converted to temperature and plotted on a linear scale against depth allowing paleo-temperature profiles and paleo-geothermal gradients to be defined. A new dimension was introduced in the 1980's with the advent of apatite fission track analysis (AFTA) providing the crucial timing element for THR.

THR revolves around the recognition of thermal episodes which represent times of cooling in the thermal history. If a rock was once at a high temperature and is now at a lower temperature then clearly it has cooled. If there has been no cooling, the rock is at 'maximum temperature now' (or MTN). In this case thermal history data will only indicate the present-day temperature. If the rock was once hot and has cooled, then it was 'hotter in the past' (or HIP) and THR can provide information on how hot it got and when it began to cool.

Cooling, Missing Section, Uplift & Erosion
Thermal history data collected in a vertical profile from a well provide a paleo-temperature profile from which a paleo-geothermal gradient can be measured. This allows valuable insight to the mechanism of heating and cooling recognised by the thermal history data. Uplift is indicated where a linear paleo-gradient is offset to higher temperatures than the present-day gradient, and extrapolation of a linear gradient to an assumed paleo-surface temperature intercept forms the basis of estimating the thickness of the 'missing section', and therefore the amount of erosion, from thermal history data.

When rocks are cooled and missing section is indicated, it is erosion that causes the cooling by moving the rock section nearer to the surface. A stratigraphic hiatus or period of non-deposition, or up/down movements of the earth's surface with no erosion, would not leave a thermal signature and would not be recognised by thermal history data. We acknowledge that erosion does not always mean uplift.

In theory the post break-up phase of passive margin development should be undergoing uninterrupted McKenzie-style thermal decay subsidence. However thermal history data along the West African and other passive margins show that this is not the case. Data from Equatorial Guinea and Cameroon show an initial high heat flow in the mid-Cretaceous then the expected trend of overall cooling to the present-day but interrupted by several extreme cooling events in the Late Cretaceous, Early Tertiary and Neogene. This is interpreted as sub-aerial erosion which requires km-scale uplift and this is supported by time gaps in wells and truncational unconformities on seismic data.

Received wisdom is that this scale of uplift and erosion only affected basin margins and that the distal domain will only have undergone simple and continuous subsidence where sediments would be at MTN. However recent work and data have thrown doubt on this view by showing that recognised episodes of uplift and erosion may extend basin-wards over transitional or even oceanic crust.

In the Gulf of Guinea, well L-2 is situated in ~ 2000m of water in the distal Rio Muni basin on proto-oceanic or transitional crust. A recent revision of the stratigraphy in L-2 has shown a significant stratigraphic break with Miocene lying on Mid-Eocene. VR data from the Paleogene section in L-2 broadly lie on a linear trend but are significantly offset towards higher values indicating HIP. The data require 1200 to 1600 m of missing section removed by pre-Miocene erosion and seismic data support this interpretation with truncation below the unconformity extending out over oceanic crust. This erosional episode correlates well with the 45-35 Ma event recognised in wells and outcrop along the basin margin.

On new regional seismic data along offshore Atlantic Morocco of the NW African margin a 'basinward-truncating unconformity' can be seen extending from stretched continental crust out over oceanic crust cutting deeply into the Cretaceous stratigraphy. In DSDP core-holes drilled on oceanic crust the oldest sediments above the unconformity are Paleocene giving a Base Tertiary age. In the distal basin DSDP 397 where the time-gap at the unconformity is Miocene to Hauterivian, VR values of 0.50-0.55% in the Hauterivian indicate removal of a significant amount of missing section.

We plan to further investigate the evidence for distal basin erosion by sampling offshore Morocco DSDP cores for new thermal history data (AFTA/VR).

Modern Petroleum Systems Analysis

Thermal history data are too frequently overlooked in petroleum systems analysis. There appears to be a general reluctance to accept large-scale uplift and erosion during post-rift passive margin development. Objections raised concern the mechanism for such large-scale vertical movements, the whereabouts of the erosional products and the mechanisms required for renewed subsidence/sedimentation. To be scientific, these objections should not invalidate the observations but rather accelerate the search for explanations.

Ignoring thermal history data and the evidence for 'missing section' can lead to spurious heat flow models, under-estimation of subsidence and misinterpretation of source rock maturity and hydrocarbon generation.
This becomes ever more pertinent as petroleum systems analysis moves into deeper water situations overlying oceanic crust, where there is a tendency to assume a McKenzie style cooling history and continuous burial and rely on theoretical modelling.

NOTES:

Sorry to intrude, but is it time to check-out of the "Motel Theory" in the Faroe-Shetland Basin?

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[2]*University of Aberdeen*
[3]*Siccar Point Energy*
[4]*Chemostrat Ltd.*

The Faroe-Shetland Basin (FSB), located on the NE Atlantic Margin, is a prolific deep-water hydrocarbon province with world-class oil, gas and condensate discoveries (e.g. Clair & Schiehallion) predominantly generated from the Upper Jurassic Kimmeridge Clay Formation (KCF) source rock. The oil geochemistry from most fields/discoveries suggests hydrocarbon charge occurred in multiple events, with the most recent no earlier than ca. 15 – 20Ma, despite most previous models invoking charge beginning during the Cretaceous at ca.100Ma, commonly explained by recent remigration from intermediary accumulations ("Hydrocarbon Hotel" or "Motel" Theory). The basin is characterized by a thick Cretaceous sedimentary package containing locally very large net thicknesses (up to 1.5 km) of Paleogene intrusive igneous material, but most are located within Cretaceous shales and are relatively thin (91% <40 m thick), below seismic-resolution and thus may have been previously underestimated. Estimating the net thickness of intrusions and removing this material restores the sedimentary sequence to its original thickness before igneous intrusions were emplaced at ca.55 – 52Ma, reducing the overburden atop the KCF source rock prior to the Paleogene and consequently reducing palaeo-maturity and the onset of hydrocarbon generation by up to 18 Myr in the Judd Sub-Basin. Additionally, once emplaced, the higher proportion of crystalline igneous material within the overburden atop the KCF increases the thermal conductivity of the package, reducing the geothermal gradient and thus the temperature of the underlying source rock at present by up to 5%. Additionally, the ca. 2.5Ga Lewisian basement is significantly older than Phanerozoic basement in the North Sea, reducing radiogenic heat production (RHP) by up to 70% (ca. 0.8 – 1.4 µW/m3) in comparison to Phanerozoic crust typical of the North Sea (ca. 2.5 – 3.2 µW/m3). Together these processes may affect the thermal history of the source rock sufficiently to delay the onset of oil expulsion by up to 40 Myr, bringing consistency to the organic geochemical and radiometric dating (Rhenium-Osmium isotopic) interpretation of oil generation age by providing a mechanism for geologically-recent hydrocarbon maturation.

NOTES:

From regional data acquisition to exploration drilling in only one year – integrated Petroleum Systems Modelling in the Tendrara Exploration area, Eastern Morocco

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[1] Sound Energy Plc
[2] IGI Ltd.
[3] Sound Energy Morocco Ltd
[4] AustinBridgeporth

Sound Energy Morocco Ltd operates the combined Tendrara and Anoual exploration permits in the High Plateau of Eastern Morocco. This large licence footprint covers almost 24,000km2 of the Moroccan High Plateau (Hauts Plateaux), a relatively undeformed Mesozoic basin bounded by the Alpine High Atlas Mountains to the south and the Middle Atlas to the West and North. The Mesozoic basin is underlain by a pre-Hercynian, Palaeozoic basin contiguous with the prolific petroleum producing basins of Algeria to the east.

Sound Energy has made a number of gas discoveries in the licences, in the Trias Argilo-Gréseux Inférieur (TAGI) formation which is sealed by an overlying, thick Latest Triassic to Early Jurassic aged salt section. Exploration has been intermittent over the past 50 years and only with the advent of modern well stimulation techniques has Sound Energy been able to prove commercial flow rates from the TAGI formation. The TAGI is a heterogeneous succession of fluvial and alluvial units and is deposited on a major angular unconformity which marks the final phase of extensive Hercynian deformation in the area.

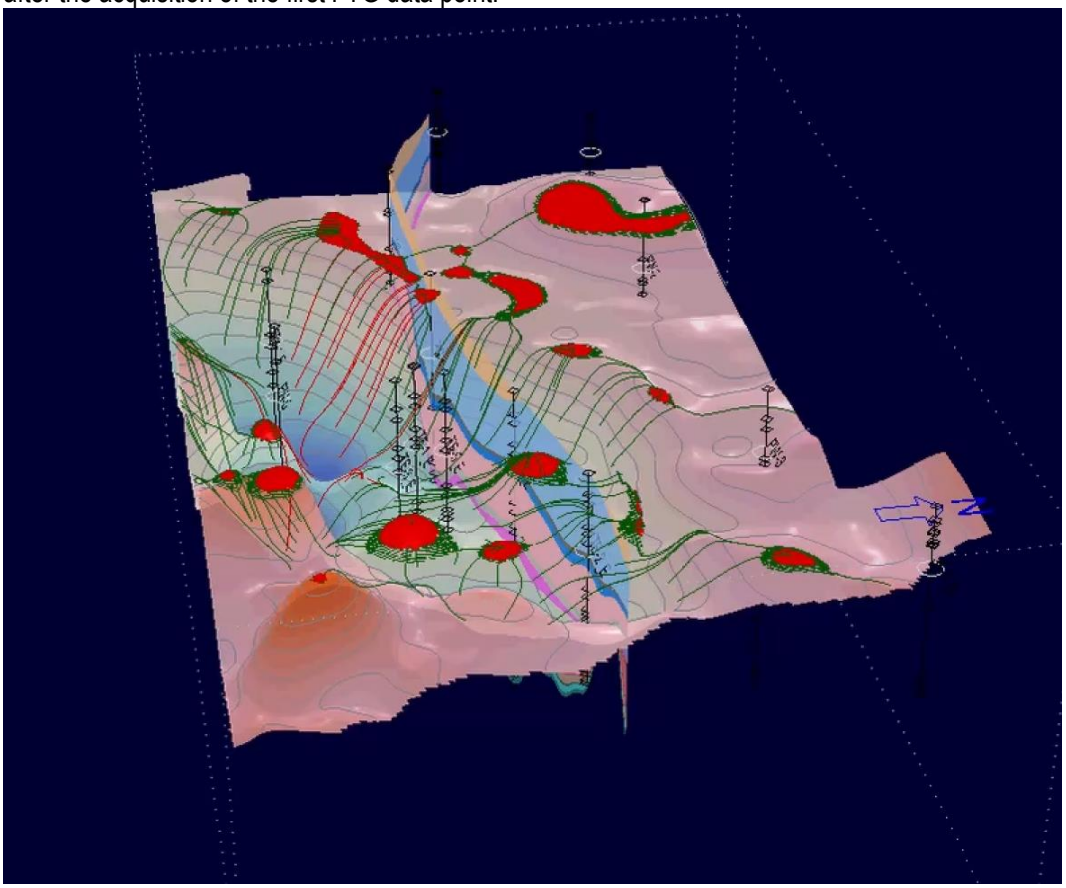
Prior to Sound Energy's work in the area, relatively little was known about the extent of the Petroleum systems across the licence. Most theoretical models were based on analogues from Algeria and assumed an Early Palaeozoic source rock was present. Only sparse well and 2D seismic data was available across the very large block. The seismic was hampered by imaging issues, meaning that the Palaeozoic sedimentary section was difficult to visualise and interpret. In order to define the extent of the Palaeozoic basin, Sound Energy commissioned a regional, airborne Full Tensor Gravity gradiometry (FTG) from AustinBridgePorth (ABI) combined with a magnetic survey across the almost the entire 24,000km2 exploration permit. This survey was acquired in late 2017 and provided a dataset that for the first time allowed the extent of the Palaeozoic basin to be defined. The FTG and magnetic data were modelled by ABI along existing legacy seismic lines which allowed key surfaces (including the basement, Hercynian unconformity, Salt isopach etc) to be interpreted across the whole block.

The FTG derived regional surfaces provided a canvas on which to build the petroleum system model. In parallel with the FTG acquisition and processing, Sound Energy undertook a number of geological and geochemical studies to provide data to populate and calibrate the model. Apatite fission track analysis (AFTA) and new biostratigraphic data was used to provide an estimate of the amount of erosion at the Hercynian aged unconformities. Samples of gases and oils from the existing Tendrara discoveries were analysed and provided, for the first time, an opportunity to type these hydrocarbons to known Palaeozoic source rocks. The stable isotope and biomarker data from the gases and condensates also provided consistent information on the maturity of TAGI fluids in the Tendrara Licence. The maturity of the fluids, combined with new Vitrinite reflectance data (VR) were tested against the new, deep Palaeozoic interpretation.

The results of this work provided Sound Energy with a rich dataset, that was used to build and constrain a truly basin scale petroleum systems model, covering the entire permit area. This model was built by IGI Ltd working closely with the Sound Energy exploration team, to integrate the empirical data and theoretical models. Sensitivities were tested, that allowed the team to evaluate the risk on the magnitude, timing and spatial variation of the petroleum system. Critically, the model could be tested against known discoveries and this enabled the team to quantify the very significant impact of the Hercynian orogeny on the temporal evolution of the petroleum system.

The product of this work was a flexible and scalable 3D basin model that was used to evaluate the Sound Energy prospect inventory across Tendrara and Anoual. The model allowed for the derisking of a portfolio of prospects to

such an extent that Sound Energy was able to execute a three well Exploration programme, starting only one year after the acquisition of the first FTG data point.



3D visualisation of Top TAGI depth surface (derived from the integration of FTG, seismic and well data). Migration paths and modelled accumulations at TAGI level are shown in green (oil) and red (gas). Vertical well calibration points are in black. The total area of the grid is approx. 22,000km2. North is shown to the right of the image.

NOTES:

Uplifted Triassic shales expose their secrets

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[2]*Exploration Geoscience*

In 1999 IGI working with Exploration Geosciences (and others) put together the first publicly available large basin wide study of the oil and gas potential on the North Slope of Alaska from the Russian border in the Chukchi Sea to the Canadian Border (ANWR). This was made possible by way of access to Western Geophysical's then 2D seismic data sets (onshore and offshore) together with a publicly available well database. This data set allowed the first large scale detailed regional structural and isopach mapping exercise to take place (outside the companies operating in the area such as BP and ARCO) developing a proper understanding of the basin's structural evolution.

On the North Slope of Alaska there are a number of oil families related to several different source rocks. In the east of the study area (the focus of this talk), which included all the main oil finds present at the time (known as the Industry Area), the main source rocks are the Shublik (Triassic), Kingak (Jurassic) and Pebble Shale (Early Cretaceous) formations and many fields (still active today) have a mix of these oils.

The gross oil in place, estimated at ~100 billion barrels as a result of geochemical and basin modelling investigations, required 1,000 billion barrels of oil to have been generated (given account for source rock retention and migration losses). Some 60% of this oil is from the Shublik. With a known yield from the Shublik source and volumes of Shublik shale present within the basins in communication with carrier beds to the oil fields, it became apparent that as Chris put it "there was a distinct lack of plausible source".

The solution turned out to be "missing Shublik shale". To the east of, and originally down-dip from, the major oil fields is the Eastern Brooks Range. Here today the Sadlerochit Mountains have the Triassic, including the Shublik shale (shown from Ro maturity data to have been burial to the late oil-main gas window) and the two adjacent Triassic aged sandstones; the Sag River Sst. and the Ivishak Fm. (reservoirs and carrier beds), exposed at surface. The Shublik in this area reached main oil maturity between 120-80ma and the expelled oil would have migrated north west up dip, into the Prudhoe Bay oil accumulations. In the Paleocene (65-55ma) the North East Brookes range including the Shublik shale was uplifted out of the oil generation window, largely eroded and no longer positioned in simple communication with the Industry Area oilfields. Hence the apparent present day "lack of plausible source rock".

Focusing on this Eastern area (Industry Area & Arctic National Wildlife Refuge ANWR) this talk will review the proposed geochemical and petroleum basin model considering 20yrs advancement in the industry.

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The Thermal History of the Weald Basin, southeast England

Tanya Beattie, John Marshall and Ian Harding
University of Southampton

The Weald Basin, located in southeast England, is one of three hydrocarbon exploration targets in the United Kingdom's onshore sector with several companies actively holding exploration licenses across the basin. Oil and gas reserves have been known in this basin for over a century, and new discoveries are still being made, as proven by the significant Horse Hill 1 discovery in 2014 and the smaller Markwells Wood field identified in 2010. However, in order to increase the probability of future discoveries, more information about the geological development of the basin is required. Jurassic source rocks have been identified throughout much of the basin; however there has been a lack of publications studying the thermal history and therefore maturity of these source rock units.

This project aims to address this gap in knowledge by modelling the burial history of wells located across the basin. Cuttings from commercially released wells have been sampled from the British Geological Survey core store. These samples have then been processed for vitrinite reflectance studies at the University of Southampton. Vitrinite reflectance data is used as the foundation of burial modelling to ensure the constructed models are a true reflection of the Weald Basin's geological history. Initial results have shown that the palaeogeothermal gradient is not simple in the Weald Basin. Vitrinite reflectance data indicates a change in the palaeothermal gradient around the Palaeozoic/Mesozoic boundary with a higher gradient occurring in the Palaeozoic and sometimes extending in to the earliest Jurassic. The palaeothermal gradient then decreases during the Mesozoic; this lower gradient overprints and intersects the older Palaeozoic gradient, resulting in a dog-leg in the thermal gradient. These palaeothermal gradients have hydrocarbon maturity implications and indicate that there may have been two separate hydrocarbon generation events in the Weald Basin.

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Some physical considerations of the kinetic models for predicting petroleum generation in geological basins

A.D. Carr[1], and C.N. Uguna[2]
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[2] *University of Nottingham*

Petroleum system modelling initially started in the 1970's, and expanded with the development of sophisticated computer software and vast amount of research into the kinetic modelling of petroleum generation, petroleum migration, etc. such that it is now widely applied in petroleum exploration. This expansion occurred at the same time as the vast increase in computer processing power, such that today it is possible to run 3-D models using personal computers. Using published studies, the kinetics of a source rock/organofacies can be experimentally obtained, or alternatively already published models for single or mixed kerogen types in source rocks in petroleum system modelling. Apart from the source richness provided by total organic carbon content and Rock-Eval, and source rock lithology, the other key factor controlling the ability of geoscientists to predict petroleum generation is the development of the palaeothermal history of the basin or prospect being modelled.

Virtually all of the kinetic models devised for predicting petroleum generation in geological basins assume first-order kinetics largely because of the results from laboratory pyrolysis experimentation, although the free-decay model for kerogen decomposition requires a high-order model. Regardless of the model order, the same physical parameters, i.e. activation energy (Ea) and pre-exponential factor (A) occur in all models, although the values may differ between the different models. The theoretical derivation for both Ea and A values are given by Ea = $\Delta U‡ + \Delta(pV)‡ + RT$ with A = $(kbT/h)\cdot e(1+\Delta S‡/R)$ where U is the internal energy (J·mol-1), pV is the mechanical (volume, pressure) work (J·mol-1), R is gas constant (J·mol-1·K-1), T is absolute temperature (K), ‡ is the activated state of the reaction, kb is the Boltzmann constant (J·K-1), h is Planck constant (J·s), and S is the entropy change (J·mol-1·K-1). In the published kinetic models for kerogen decomposition to hydrocarbons the Ea and A are derived either graphically or by using computer software. However, using a previously published parallel reaction Type I kinetic model (Burnham et al., 1987) as applied to the Dongying Depression, Bohai Bay Basin China (Guo et al., 2011), then the predicted volumes of petroleum generation can be derived. The total $\Delta(pV)‡$ value contained in laboratory derived kinetic models is approx. 10 kJ J·mol-1, whereas using the overpressure values of Guo et al. (2011), the actual total $\Delta(pV)‡$ value is approx. an order of magnitude higher, suggesting that energy is not conserved in the current independent of pressure petroleum generation kinetic models.

Rearranging the Ea equation to give an expression for volume V ($V = (Ea - U‡ - RT)\cdot p\text{-}1$), together with published U‡, and $\Delta S‡$ values for kerogen (Stainforth, 2019), and the basin PT values then the predicted volumes using the conventional kinetic model can be compared with those derived using a model that conserves energy. When the predicted volumes derived using a pressure of 1 Pa for all depths in the predicted oil generation window (2 to 4.2 km), then the predicted volumes are exactly the same as those generated by the conventional (Burnham et al. 1987) kinetic model (Fig. 1). This is important since it shows that the V term is a kinetic and not a thermodynamic value; kinetics is concerned with the rates of change in reactant concentration, whereas thermodynamics deals with the changes between the beginning and end of the reaction. When the pressures are increased to hydrostatic or overpressured values, then the predicted volumes are significantly lower than those predicted at 1 Pa for the entire well (Fig.1). These results indicate that the failure to include realistic pressure values in the kinetic models, means that the current petroleum pressure-independent kinetic models do not conserve energy, since as soon as the appropriate pV energy term is used, the volumes of products predicted cannot be supported by the current geological basin temperatures, as we know that the conservation of energy law applies to subsurface environments. The thermal history (not the present-day well temperatures) frequently devised for petroleum system models are often derived partly using kinetics will be incorrect, since the current equations for predicting thermal histories do not conserve energy, with the result that the temperature histories are 10 °C·m-3 higher for each km of subsidence than predicted by current thermal histories. The effect of this temperature increase will be to provide some of the additional thermal energy required for the pV work, although the Ea and U values must still be modified to produce models that conserve energy and predict the appropriate petroleum volumes during a basin's burial history.

The A values in virtually all published models for kerogen decomposition have constant values, whereas it is variable as is controlled by the reaction temperature and entropy change (S‡). The S‡ are positive as would be expected from decomposition of solid kerogen into liquids and gases, and small as described by Stainforth (2009). The computed fA values are generally lower than the constant value in the model of Burnham et al. (1987). The use of lower A values partly (although not entirely) compensate for the increased Ea values produced by the pV work effect. A new kinetic model devised to conserve energy through the use of realistic Ea, U, pV and A values will be described for Type I kerogen and applied to the Dongying Depression.

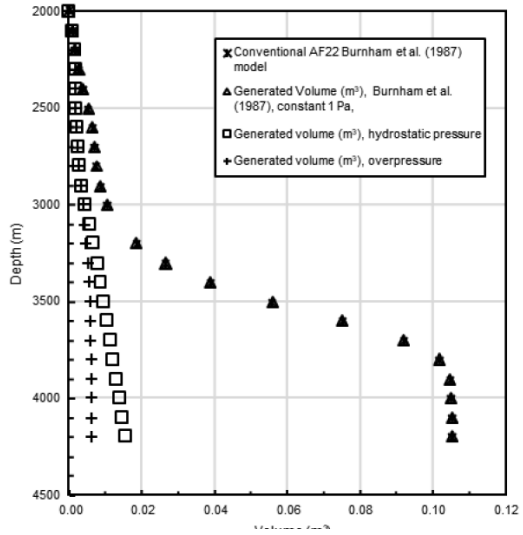

Fig. 1 Graph showing the same petroleum volumes during Dongying Depression subsidence using the conventional kinetic method and that devised when P = 1 Pa at all depths. Increasing the pressure to either hydrostatic or overpressure produces significantly lower volumes than predicted by the conventional pressure absent model

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Poster Abstracts

PyroViewer – a new Rock Eval data evaluation tool

Markus Doerner[1], Ulrich Berner[2], Michael Erdmann[2], Tanja Barth[1],
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[2]*Equinor ASA*

Rock Eval data is one of the most frequent data types used in petroleum research and industry. Since the first Rock Eval was introduced to the market, major improvements have been implemented, both on the hardware and software side. Although user-friendliness has significantly improved, it is still laborious to perform an extensive quality check of the data involving a comprehensive interpretation pyrograms especially when it comes to larger well studies.

We therefore present a new tool which helps to check the quality of raw Rock Eval data and enables the user to get a comprehensive view on Rock Eval pyrograms. The "PyroViewer" is a MATLAB® script, which is capable of directly utilizing and interpreting Rock Eval pyrogram data. This is of significant value in well studies, as all pyrograms now can be displayed in a 3-dimensional rotatable well view. In addition, we demonstrate integration of the new Rock Eval shale method proposed by Romero-Sarmiento et al., 2015.

This visualization helps to identify sections of interest, but also supports quality control as it automatically visualizes the quality of the individual measurements. This is very helpful when it comes to contaminations when mud additives were used during drilling. Each Rock Eval S2 peak is automatically curve fitted and evaluated. This enables the program to subtract possible contamination from the original S2, providing a more realistic corrected S2. This also has the side effect that less parallel solvent extraction is needed in the laboratory. In addition, we present an integration method of the S2 which provides a helpful indication for changes in the type of the organo-facies.

A dataset based of 220 sediment samples from the BH 10-2008 well at Sysselmannbreen in the Tertiary Basin of Svalbard demonstrates the potential of the new methodology.

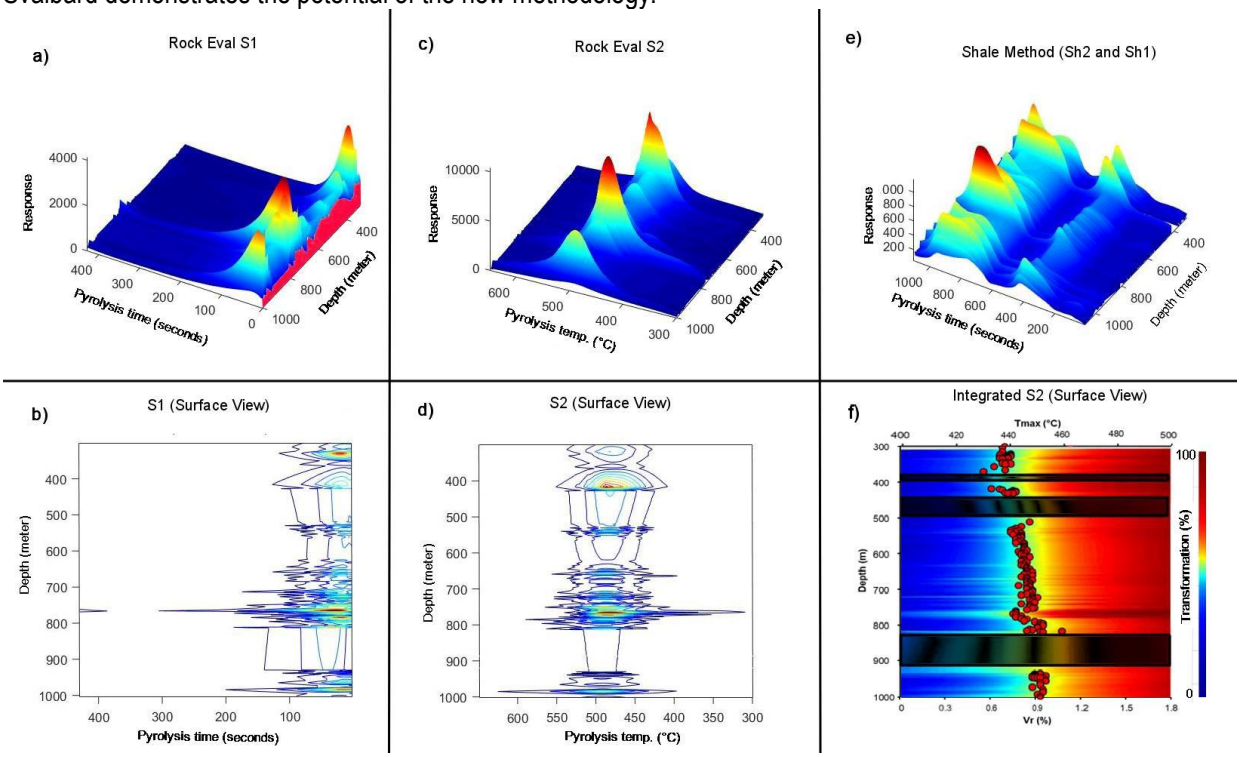

Figure 1: Compositional picture of the PyroViewer output for the well BH 10-2008 Svalbard. a) Amount of Rock Eval Bulk method S1 fraction vs well depth. The red area highlights the loss of light hydrocarbons due to the pyrolysis starting temperature of 270 °C. b) Surface plot (peak top view) of the Rock Eval Bulk S1, showing highest S1

responses in red. c) Rock Eval Bulk Method S2 vs well depth. d) Surface plot (Peak top view) on the Rock Eval S2, areas of higher potential are marked in red. e) Peak shape overview for the new Rock Eval shale method (Romero-Sarmiento et al., 2015). No light hydrocarbon loss could be observed with this method. f) Curve fitted and integrated S2 peaks representing the transformation curves for individual samples. Changes in the organic matter type are expressed as changes in the steepness of the transformation function. Red points indicate the Tmax and Vr values which were measured with the Rock Eval Bulk method. Black shaded areas represent section without data.

The Hydrological Cycle During Deposition of the Mahogany Oil Shale Interval of Eocene Lake Uinta, Green River Formation, Utah

Amy L. Elson[1], Megan Rohrssen[2], John Marshall[1], Jessica H. Whiteside[1]
[1]*National Oceanography Centre Southampton*
[2]*Central Michigan University, USA*

The Green River Formation of Utah and Colorado represents a ~15 million-year Lower Eocene record of unusually large, productive lakes which deposited an estimated 750 billion barrels of oil equivalent, one of the largest oil shales in the world. Multiple drill cores through the Mahogany Oil Shale Zone, taken from both the basin margin and center, offer an excellent opportunity to construct high-resolution records of terrestrial conditions and explore their influence on organic matter deposition and preservation.

In this study, the isotopic expression of mid-latitude hydrological change during an unusually rich TOC (up to 40%) interval is investigated through compound-specific hydrogen isotopic analyses of n-alkanes extracted from the Mahogany Oil Shale Zone, Uinta basin, Utah. Comparison of this novel record with high-resolution sedimentary logs will allow for greater understanding of the hydrological cycle at the time of deposition of this key oil shale.

Disentangling the factors controlling deposition and preservation of organic matter in the Green River Formation through a combination of organic geochemical and sedimentological tools will lead to greater understanding and predictability of the organic-rich layers in the oil shale. This will help improve modelling of lacustrine source rocks and will also support the development of the U.S unconventional hydrocarbon industry, and petroleum independence in the region.

UK North Sea oils geochemistry: Interpreting newly acquired data from legacy oils

Akinniyi A Akinwumiju[1], Paul Farrimond[1] and Gareth Harriman[2]
[1]*Integrated Geochemical Interpretation, Ltd.*
[2]*GHGeochem Ltd.*

The geochemical characteristics of a suite of oils in the UK North Sea have been reviewed by interpreting recently-acquired whole oil GC, biomarker and stable carbon isotope data for 76 legacy oils. The bulk of the oils appear not to have undergone any significant oil alteration processes including biodegradation, water washing and evaporative fractionation based on gasoline composition, although three oils (from Toni field (well 16/17-16) & well 16/12A-4) plot as residues of phase fractionation, and some other oils show less obvious evidence of this process. Six oils including those from Fyne & Dandy and Captain fields show moderate to severe biodegration with the loss of all n-alkanes.

Alkane, aromatic and sterane biomarker maturity parameters indicate early to normal oil window maturity for most of the samples, with the oils from the central part of the North Sea predominantly showing apparently lower maturity compared to samples from other areas. These maturity interpretations suggest that most of the oils have been sourced from early to mid-oil window mature source rock(s). The oils are broadly grouped into a single genetic family and are isotopically light with the stable carbon isotope composition of the saturated hydrocarbon fraction of the oils mainly in the -31 to -29 ‰VPDB range.

On a cross-plot of the stable carbon isotopic composition of the saturated hydrocarbon fraction against the pristane/phytane ratio, the bulk of the oils show a very good correlation to the extractable organic matter from Upper Jurassic Kimmeridge Clay Formation (KCF) samples with possible contributions from the more terrestrially influenced Middle to Upper Jurassic Heather Formation.

The apparently lower maturity (early oil window) indicated for some of the oils is most likely due to sourcing from localised kitchens where the Kimmeridge Clay source rock contains a significant proportion of Type IIS kerogen, which typically would generate oil at a lower maturity level than normal Type II KCF facies. Most of the oil samples from the central part of the UK North Sea have abundant extended hopanes with high C35 /C34 hopane ratio, indicative of a more reducing sulphidic KCF source facies.

Geochromatographic separation of organic tracers using a natural Draupne (Kimmeridge Clay) source rock column

Florian M. Panitz[1], Michael Erdmann[2], Ulrich Berner[2], Lorenz Schwark [1,3]
[1]*Kiel University, Germany*
[2]*Equinor*
[3]*WA-OIGC, Curtin University*

Introduction
The flow of petroleum out of a source rock is called primary migration. Although the understanding of primary migration has grown significantly over the last decades, the processes operating during this earliest stage of petroleum movement still remain highly elusive. Research in the past has, however, provided circumstantial evidence that primary migration is associated with substantial molecular redistribution between source bitumens (asphaltene/resin-rich) and crude oils (hydrocarbon-rich) (e.g. Mackenzie et al., 1983; Leythaeuser et al., 1984, 1988). Essentially, three major reasons for such fractionation have been discussed: (1) diffusion, (2) kerogen absorption, and (3) geochromatographic interactions. In this study, we performed a column flow experiment to investigate particularly the impact of expulsion geochromatography (Krooss et al., 1991) on selected organic tracers.

Procedures
A tracer stock solution with defined molecular composition was passed gravitationally through a column filled with ground, solvent-extracted, and 10% water-saturated (ASE, Soxhlet) mature Draupne source rock dispersed in a synthetic oil (Fig. 1). In total, 32 fractions of different

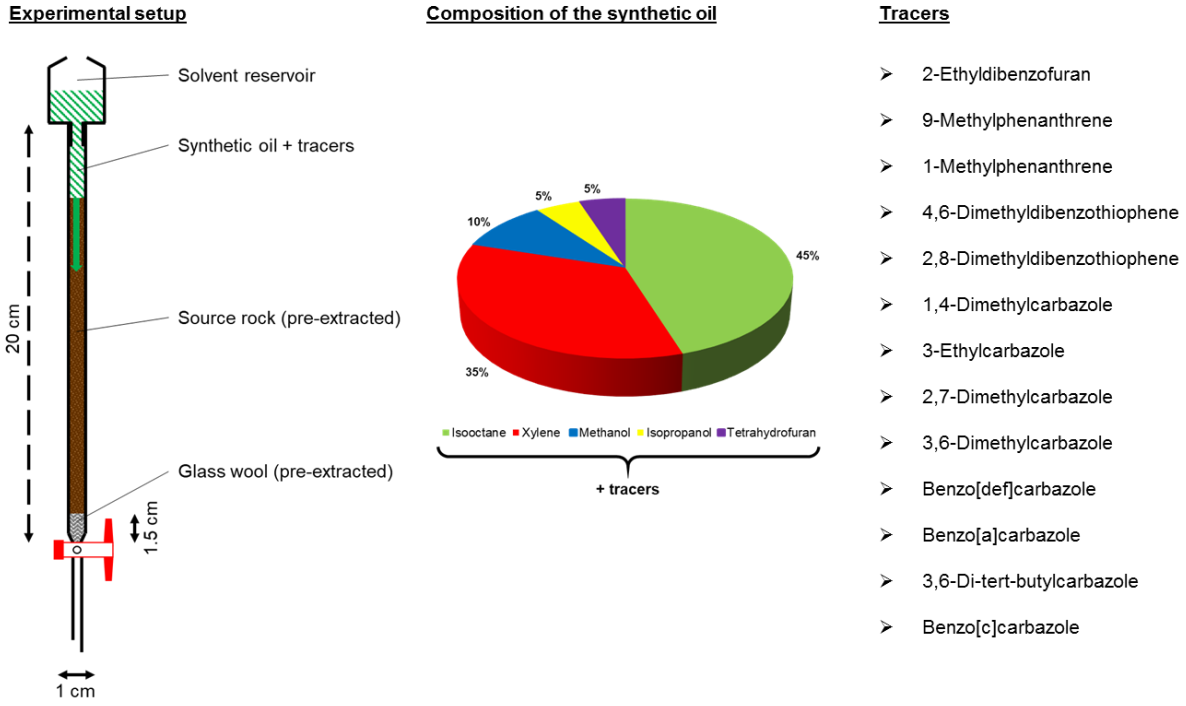

Fig. 1. Schematic concept of the column flow experiment. Essentially, 2 ml of tracer solution containing selected organic compounds were passed gravitationally through a powdered, compacted, solvent-extracted, and 10% water-saturated (ASE, Soxhlet) oil window mature Draupne source rock column (20 cm x 1 cm, 15 cm filling height) via a synthetic oil to investigate the influence of geochromatography on the composition of the tracer solution. Altogether, 32 fractions of different volumes (0.8-8.0 ml) were collected, desulfurized, and prepared for GC-MS analysis. 10 µl of 9-phenylcarbazole (10 µg/ml) were added to each fraction as internal quantification standard.

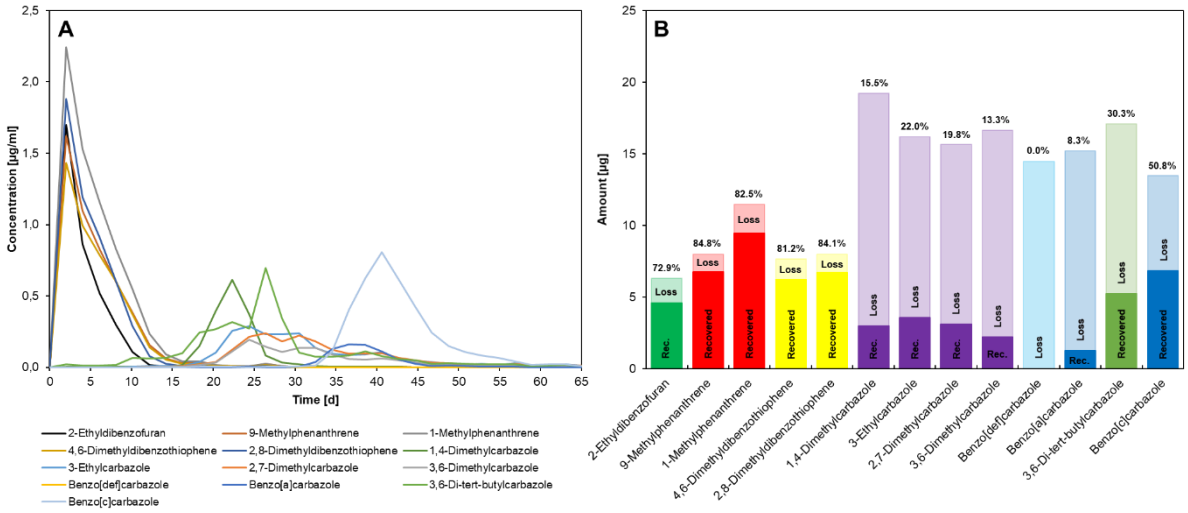

Fig. 2. Preliminary results of the column flow experiment. A: Concentrations of tracer molecules in the fractions eluted over time. While the alkylated dibenzofuran, the phenanthrenes, and the dibenzothiophenes passed the column rapidly, carbazoles were retarded, whereby the partially shielded 1,4-isomer migrated faster than the exposed isomers. Among the benzocarbazoles, benzo[a]- migrated slightly faster than benzo[c]carbazole. B: Recovery rates of tracers added are given above columns. Note that the carbazoles were strongly retained by the source rock column compared to alkylated dibenzofuran, phenanthrenes and dibenzothiophenes. Interestingly, comparatively large amounts of benzo[c]carbazole were recovered relative to benzo[a]carbazole and the C2 carbazoles. Conversely, around 3/4 of the furan, and 4/5 of the phenanthrenes and dibenzothiophenes were recovered.

volumes (0.8-8 ml) were collected and quantitatively analyzed by GC-MS after addition of 10 µl of 9-phenylcarbazole (10 µg/ml) to each fraction as internal quantification standard.

Results

Results are presented in Fig. 2 and demonstrate a "geochromatography" effect within a source rock, expected to mimic fractionation occurring upon expulsion. Whereas geochromatography during secondary migration has been studied intensively, fractionation upon expulsion has not been addressed in experiments that often. Our experiments document the separation of the tracer solution via a source rock column and a synthetic oil reflecting the principal composition of a natural crude. In particular, the results show that alkylated dibenzofurans, phenanthrenes, and dibenzothiophenes eluted much earlier than the alkylcarbazoles. Among the carbazoles, the C2 carbazoles migrated faster than the benzocarbazoles, from which benzo[a]- passed the column faster than benzo[c]carbazole. Regarding the migration behavior of nitrogen-shielded vs. nitrogen-exposed C2 carbazoles, the data indicate that the partially shielded 1,4-isomer migrates faster than its pyrrole-exposed analogues. Furthermore, a mass balance approach revealed that approximately 3/4 of the dibenzofuran, and 4/5 of the phenanthrenes and dibenzothiophenes were recovered. In contrast, the majority of the carbazoles remained on the column, probably adsorbed to clay minerals and organic material. Interestingly, however, substantial amounts of benzo[c]carbazole were recovered, indicating overall weaker interaction with the stationary phase. No traces of benzo[def]carbazole were detected in the eluates, suggesting that this component is completely retained by the source rock column. To complete the mass balance approach, it is planned to demineralize source rock aliquots in order to release mineral matrix bound tracers using hydrofluoric acid and solvent extract the target components.

A hydrocarbon biomarker study in the Cleveland Basin, North Yorkshire: implications for the end-Triassic mass extinction event

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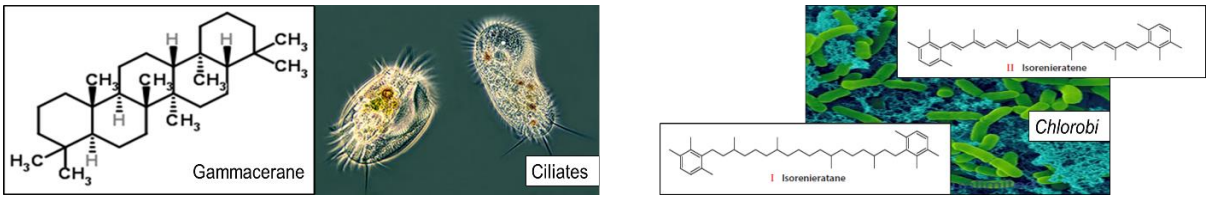
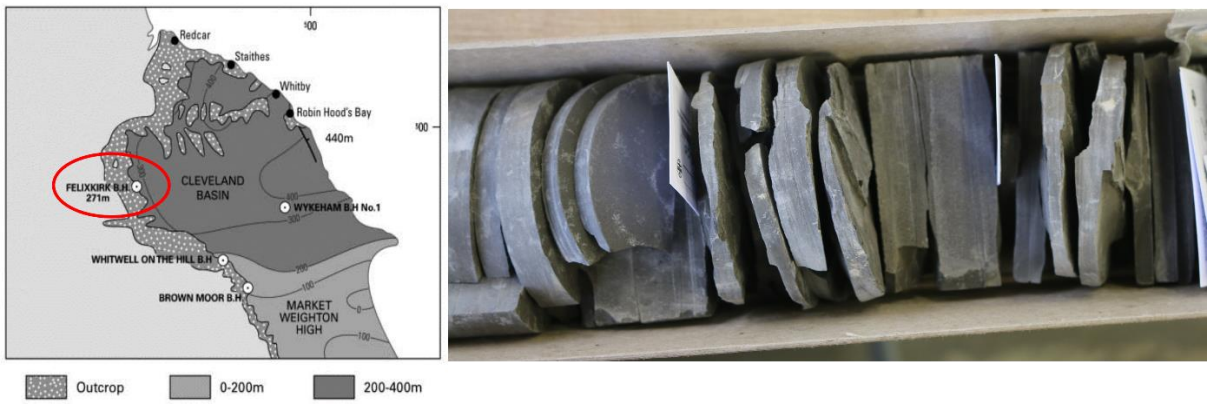
The break-up of the supercontinent Pangaea throughout the Triassic and Jurassic is associated with giant flood basalt eruptions of the Central Atlantic Magmatic Province (CAMP). Pulsed CO2 outgassing from CAMP volcanism is plausibly a major driver of the end-Triassic mass extinction (ETE) ~202 million years ago, one of the five major extinction events in the Phanerozoic. A large perturbation in the carbon cycle is recorded in many global sedimentary sections encompassing the Triassic - Jurassic boundary.

In this study, we use a multi-proxy approach based on lipid biomarkers, bulk δ^{13}Corg data and published palynological data to reconstruct a continuous high-resolution geochemical record of environmental conditions preceding the ETE, during the extinction event and throughout the recovery phase. In particular, fossil derivatives of the specific pigment isorenieratene (derived from green sulphur bacteria Chlorobiaceae) are used in conjunction with a suite of redox-sensitive biomarkers to test the hypothesis that nutrient cycle disruption and water column stratification produced widespread photic zone euxinia (PZE) during the ETE, potentially acting as an oceanic global kill mechanism.



Characteristic biomarkers for stratified water and photic zone euxinia.

A BGS drillcore from the Felixkirk Borehole, located on the western margin of the Cleveland Basin, North Yorkshire, provides a near-continuous sedimentary record across the ETE. Constraining the timing and pattern of local sea level change is imperative in understanding the extent and persistence of PZE in this area during the extinction. We analysed late Triassic (Rhaetian) and early Jurassic (Hettangian) sediments from the lowest sections of the core, which consists of mudstones interbedded with micritic limestones.



Location of the Felixkirk Borehole and a core photo of part of the studied interval.

A large, abrupt negative carbon isotope excursion (CIE) from -23.34 ‰ to -28.77 ‰ occurs at a depth of 288.94 metres in the upper Cotham Member, part of the Lilstock Formation as recognised in south west England. Preliminary biomarker data showing the presence of gammacerane and diagenetic break-down products of isorenieratene indicates there were variable euxinic conditions in the late Triassic at Felixkirk; however, establishing a firm temporal link between CAMP eruptions, sea level change, redox conditions and the extinction remains problematic.

A geochemical analysis of Triassic source rock of the 7th member of Yanchang formation in Erdos basin, China —— the comprehensive effect in paleoclimate, biological thrive and the potential lacustrine current

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The 7th member of Yanchang formation (Chang 7 formation) in Triassic system of Erdos basin in is widely recognized as one of the vital source rock for the China's unconventional resource, which is also one of the main focus of scholars in oil and gas industry and an interesting respect in geological research. For a deeper understanding of the geological characteristics and its mechanism of Chang 7 formation, a geochemical analysis is practiced in this study. For a better guarantee of the reliability of acquired result, Different kinds of geochemical data are analyzed in the respects of isotope mineral and organic matter, in order to indicate an interesting possible cause about source rock forming for Chang 7 formation.

From applying TOC and isotopic data about organic carbon and oxygen, as well as DIC, it can be explained that the characteristic of paleoclimate is typically humid and hot, which caused a low intensity in evaporation during the depositional stage (Fig. 1). According to the relationship between contents of Zr and SiO2, the origin of silicon in shale is mainly terrestrial but not biological, which indicates the lower hydrobionts such as blue algae (i.e. Cyanophyta) with low content of silicon is the main contribution to TOC (Fig. 2). It indicates a relatively high water temperature around 19.5~20ºC. Through analyzing the total hydrocarbon generation from pyrolysis (PG) and content of pyrite and siderite, a general correlation with frequent fluctuation between them can be observed, which may present a remarkable impact of minerals transited from the sedimentary source (Fig. 3). In the respect macro elements, a positive relationship about the content of P, S and TOC can be respectively observed, which also advocates such cognition (Fig. 4). By recovering the original TOC, there is an irregular ring-like characteristic distribution, which suggest the richness of organic matter is related to the quality of waterbody of different location in the basin (Fig. 5).

Based on the analysis for different kinds of geochemical data. A logical and comprehensive geological understanding to the source rock of Chang 7 formation can be acquired. Due to the humidity and high temperature in climatic condition, a relatively high intensity weathering is quite developed, which transit the minerals into the basin. The elements such as P and S which are stimulative to the occurrence of the events about the thriving of lower hydrobiont is influenced by a levorotatory potential paleo-lacustrine current. This effect is with an influence to the distribution of favorable source rock of Chang 7 formation, which can be applied in the exploration for tight shale reservoir.

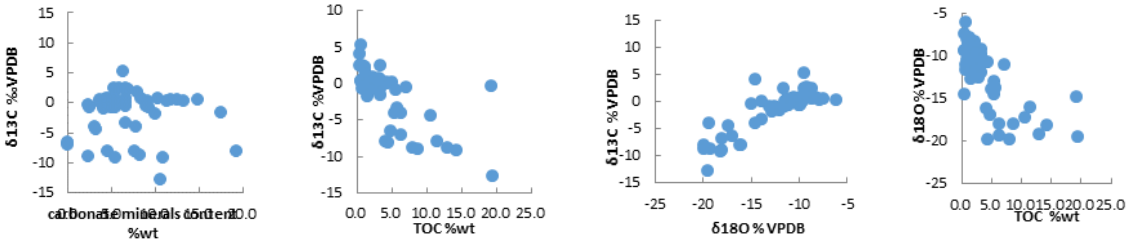

Fig. 1 Crossplots related to carbon and oxygen isotope

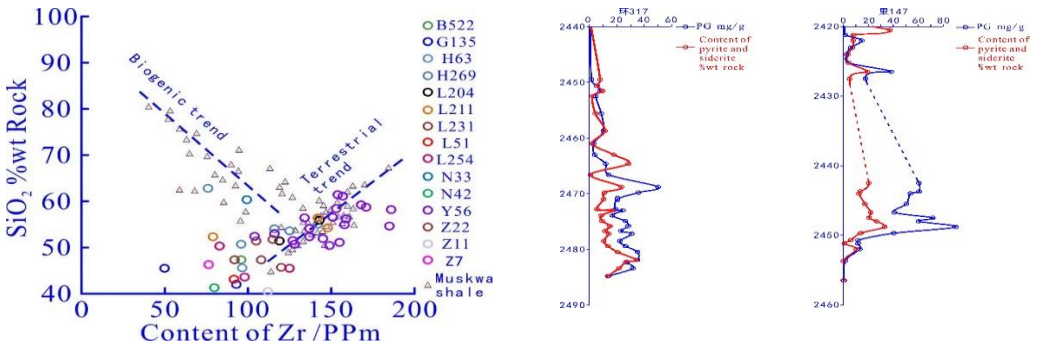

Fig. 2 The Origin of silicon in shale

Fig. 3 The relationship between PG and the content of pyrite and siderite

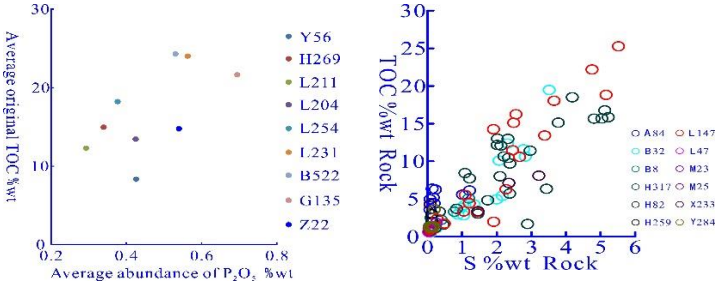

Fig. 4 The relationship between macroelement P and S to content of organic matter

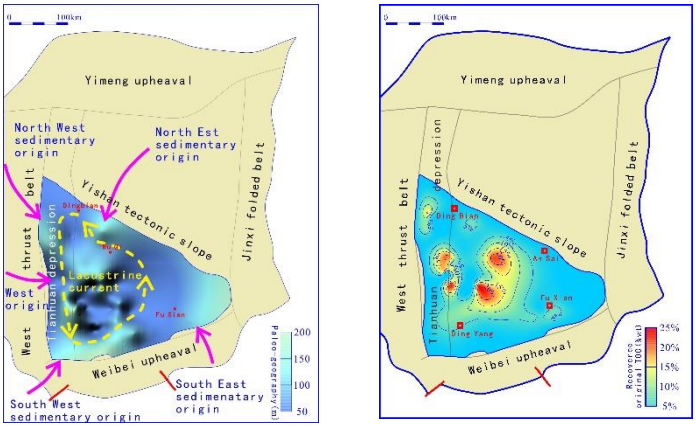

Fig. 5 The impact of paleo lacustrine current and the distributional characteristic of recovered original TOC

Demineralisation Study Shows Preferential Oil Storage in Kerogens Within Mature Kimmeridge Clay in the North Sea

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Rock-Eval pyrolysis and organic petrographic analyses of mature whole-rock samples and isolated kerogen from the Upper Jurassic Kimmeridge Clay Formation North Sea were used to better understand the quality of organic matter, kerogen type, and maceral composition. In addition, thermal maturation and generative potential were evaluated based on whole-rock and isolated kerogen results. The average total organic carbon (TOC) content of these shales is over 2% in the whole rock, and over 50% in the isolated kerogen samples; kerogen is primarily a mix of Type II and Type III, with minor amounts of Types I and III based on pyrolysis and organic petrographic results.

Petrographic observations indicated that silicate minerals, such as quartz and clays, and carbonates had been removed by the acid demineralisation process but that pyrite remained in the samples. This is to be expected as the demineralisation did not include HNO_3 (often used to remove pyrite) as this can alter OM, particularly bituminite. Petrographic observations on the isolated kerogens show liptinite (bituminite and alginite) and vitrinite dominate, but significant inertinite contents are also present. The distribution of kerogen types is similar in both the isolated kerogen and whole rock suggesting no effect of mineral dissolution on the relative abundances of organic matter macerals. This is further supported by a modified pseudo-Van Krevelen correlation plot of HI (mg/gTOC) versus OI (mg/gTOC).

Rock-Eval T_{max} and vitrinite reflectance measurements place the samples within the oil window, and generated oil is still retained within the organic-rich shales. The HI values are slightly higher in the whole rock samples, range: 84-596 mgHC/gTOC and an average 255 mgHC/gTOC, while the HI values for isolated kerogens range from 103-424 mgHC/gTOC with an average of 235 mgHC/gTOC. S1 yield from isolated kerogen plus non-reactive minerals left after the HCl/HF maceration (pyrite, ralstonite) ranges from 19-105 mgHC/g rock (average 40 mgHC/g rock), while the whole rock S1 values derived from the free oil in the kerogen plus minerals (carbonate, silicates, pyrite) range from 1-10 mgHC/g rock (average: 3.7 mgHC/g rock. Recorded T_{max} for both isolated kerogens and whole rock is between 423-454 ˚C (averaging 438˚C), showing relatively uniform values in both set of samples; suggests that there is no any significant effect of HCl/HF treatment during the kerogen isolation from minerals matrix. The potential to retain a significant amount of oil (S1) appears to be associated with the kerogen and not the mineral phase. There is no correlation between S1 and any of the maceral group abundances; these findings are relevant for understanding source rock expulsion efficiencies and unconventional exploitation of shale reservoirs with mixed kerogen assemblages.

Organic geochemical insights into the Cretaceous Western Interior Seaway

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The Western Interior Seaway (WIS) is a highly productive hydrocarbon basin that does not show expected global trends during OAEs. During the mid-Late Cretaceous it spanned the Boreal realm of the Canadian Arctic through to the Tethyan realm of the Gulf of Mexico. A shallow, epicontinental basin, it was highly influenced by changing eustasy, tectonics and climate, and full transgression from north to south occurred intermittently.

As part of this study an extensive database of published organic geochemical data has been compiled for the Cretaceous WIS (Figure 1). This dataset illustrates enhanced organic matter in sediments deposited during the 2nd order transgressions associated with the major OAEs in the Niobrara and Greenhorn cycles. However, when looking at a higher-resolution many authors have found that anoxia is diachronous with the true timing of the OAE, and actually present evidence for increased oxygenation at this time (e.g. Arthur and Sageman, 1994; Leckie et al., 1998, Lowery et al., 2017). These findings raise questions as to the true drivers behind anoxia and subsequent organic enrichment in the WIS, and suggest significantly locally-driven factors.

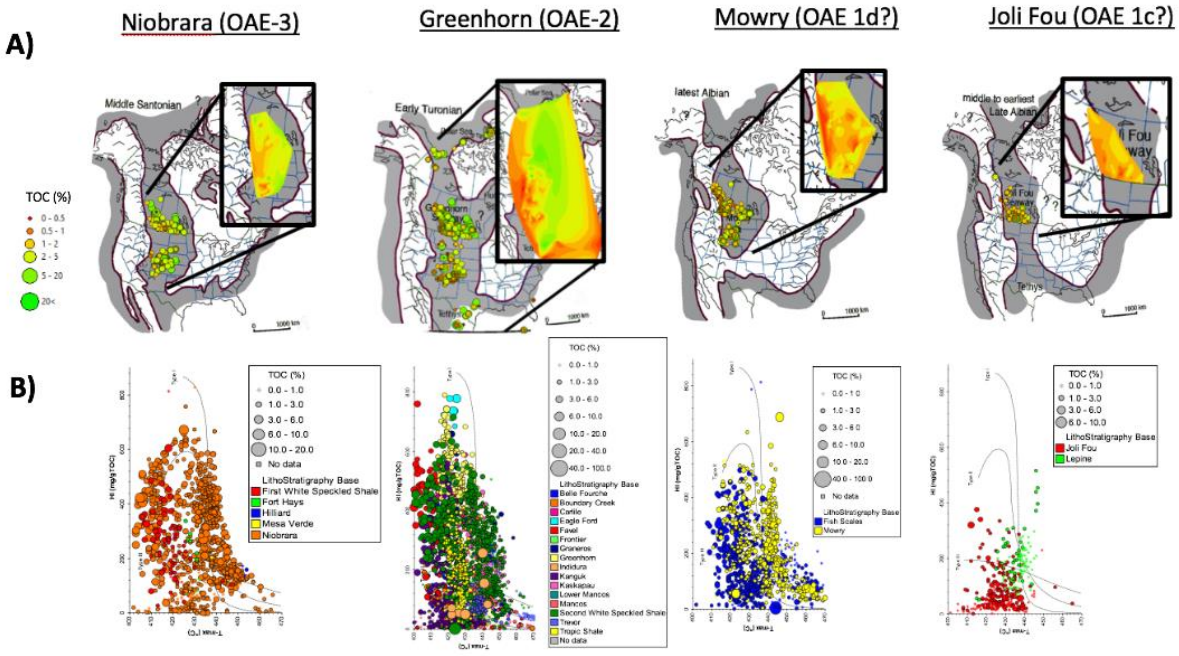


Figure 1: Rock-Eval data for four main transgressions in the Cretaceous Western Interior Seaway: A) Total Organic Carbon data displayed spatially as data points and interpolated from these values; B) HI vs Tmax parameters displayed with different lithostratigraphic units highlighted.

Lipid biomarkers and their isotopic composition have been used to study Cenomanian – Turonian sediments at a high resolution along an E-W transect in the central WIS. When reconstructing variations in water column oxygenation, stratification, and organic matter provenance various challenges have been encountered with regard to interpreting the biomarker data. With the exception of one sampling location the two redox proxies used (pristane/phytane and C35 homohopane indices) do not correlate well in their interpretation of depositional environment. Additionally the stratification proxy, gammacerane index, is often higher during more oxygenated conditions at each site, and during OAE-2 when stratification is hypothesised to have decreased in this area. The relative abundance of steranes however does suggest a less stressed biotic environment during OAE-2.

The relationship between oleanane and gammacerane refutes the idea of enhanced salinity stratification due to increased river input, and suggests that times of increased precipitation and storms actually increased the overturning of a relatively shallow seaway. The high oleanane content at the most 'distal' site suggests a well vegetated eastern hinterland with a significant presence of flowering plants.

Further work is to be undertaken across this transect to elucidate the physical and biogeochemical evolution of this seaway. Additional biomarker proxies for anoxia will be investigated, alongside trace metal and iron speciation analysis, and palynology will be assessed to determine organic matter origin.

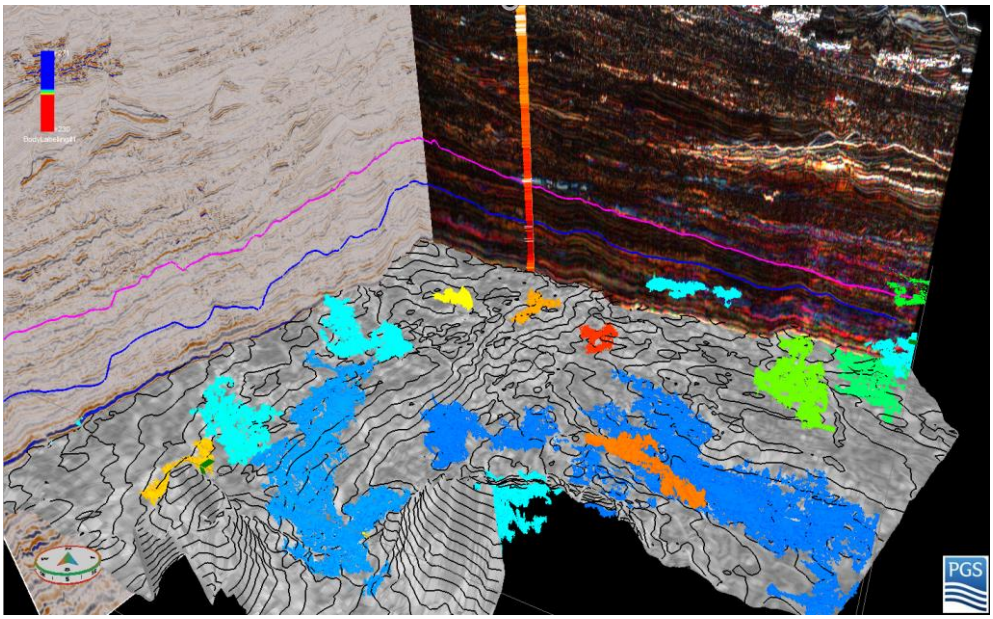
Petroleum system analysis and prospect identification using a multi-attribute volumetric approach

Gaynor Paton and Andrew Pomroy
GeoTeric

Seismic data contains a wealth of information about the subsurface geology and is the primary data source for understanding the petroleum system in frontier or exploration areas. Traditionally this is done in a map based manner, but modern interpretation techniques involving multi-attribute colour blending and interpretation means that the information contained within the high quality data that is now available can be accessed very quickly to provide greater geological insights.

In this study, we use a 4500km^2 broadband PSDM data set (BM-SEAL-4-10-11 Geostreamer 3D, courtesy of PGS) to calculate attributes that reveal elements of the total petroleum system in the Sergipe-Alagoas Basin, offshore Brazil. We use a multi-attribute approach which includes structural/edge attributes combined to reveal potential trapping mechanisms and hydrocarbon migration pathways as well as frequency decomposition and AVO to reveal the source, seal, and reservoir. Using volumetric facies classification along with colour blending and multi-attribute visualization, we can then build a volumetric "Common Risk Segment" representation of revealed prospects. This approach allows us to rapidly reveal prospects which can be risk-ranked using a composite common risk segment framework.

By combining the latest standards in seismic acquisition and processing, and marrying that to a modern seismic interpretation method, we were able to reveal, interpret and de-risk hydrocarbon accumulations in a wide area, ultra-deep water setting accurately in the space of just two weeks. This approach clearly demonstrated the benefits of using the highest quality data and interpretation methods, meeting the requirements of faster project turnaround, reduced risk, and no compromises on information quality.



Seismic data is proprietary to PGS Investigacao Petrolifera

Generalized Petroleum Generation History Model of the Upper Cretaceous Source Rocks in Sirt Basin, Libya

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[4]*Libyan Petroleum Institute*

This regional study is based on modeling the petroleum generation history of the Upper Cretaceous source rocks in Sirt Basin in the central north of Libya with an approximate area of 600,000 km^2, which is the largest, youngest, and richest petroliferous sedimentary Basin in Libya and Africa. Our two generalized models were based on analysis of the geological and geochemical data set of 230 selected wells in the area. Basin modeling approaches were extensively used during this work including 1D, 2D, and 3D techniques throughout the basin. The Upper Cretaceous source rocks in the basin have the highest influence on the petroleum system in the Sirt area. Thus, the main aim from this work is to establish the time, amount, and phase that expelled petroleum from the Sirte shale and Rachmat formations source rocks (Rakb group), both of these source rocks have been analyzed in the Sirt basin based on their geological setting and the geochemical characteristics (richness and maturity).

The simulation results that were obtained to establish two petroleum generation models of the Upper Cretaceous source rocks in Sirt basin after the source kitchen area was identified (Fetch area 285744.47 km^2) including the main basin troughs only from where the present-day petroleum accumulation charged. However, the generalized maturity model also established by using two modeling approaches (LLNL and ARCO) based on 1D information input from 39 selected wells, this maturity model is the main control parameter to generate both of the petroleum generation history models. The obtained maturity range of the Upper Cretaceous source rocks mainly ranged from mid to late-mature level. The Rachmat formation with marine kerogen type I/II started to generate petroleum in the middle Paleocene (48 M.y) in two phases mainly oil and gas. Similarly, but in different amount (HC expelled amount), the marine kerogen type I/II Sirte shale started to generate the different amount of hydrocarbon during middle Eocene time (63 M.y), but the peak generation started in the early of Oligocene time, both of the source rocks show a strong tendency to generate oil than the gas phase due to the dominant marine kerogen type. The petroleum phase that expelled from the Sirte shale was similar to that of the Rachmat formation but in different quantity. The predictions that were acquired from the modeling of the physical property GOR in range of (300-700 scf/bbl) and API gravity in rang of (30-45) for the expelled petroleum obtained simultaneously with the generation models, were also simulated in conjunction with the geological time during the expulsion process for both the source rocks i.e. Rachmat and Sirte shale.

Keywords: Expulsion phase; Generation History; Sirt Basin; Sirte Shale

Hydrocarbon Generation and Migration modelling of the Barremian-Aptian Source Rock unit of the northern Orange Basin, South Africa

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[2]*University of Witswatersrand, Johannesburg*

Keywords: Hydrocarbon migration, Petroleum system, Orange Basin

The present study analyses the faults and petroleum systems models of the northern part of the Orange Basin. A 3D numerical modelling of hydrocarbon-generation and migration from the Barremian/Aptian source rock intervals in the northern Orange Basin was performed using boundary conditions (HF, SWIT, PWD) to juxtapose the timing of hydrocarbon-generation, expulsion and tectonic faults formation.

The Model reveals transformation of organic matter began from the graben-filled central part around 108Ma and increases towards the fringes and reached the peak during the late Cretaceous. As at present day (0.0Ma), 100% transformation of organic matter had generated hydrocarbon at the central part while the extreme northeastern section is yet to be transformed into hydrocarbon. Source rock bulk generation and expulsion statistics as at present day show that 430701.94Mtons of gas and 38399.53Mtons of oil had been generated by primary and secondary cracking processes, representing 91.81% and 8.19% of organic matter transformed into gas and oil respectively.

The source rock has an expulsion efficiency of 0.77 indicating good efficiency. 1D Calibration of this model using wells AO-1, AE-1 and AF-1 drilled in the study area shows modelled temperature agrees with the calibrated temperature data in all the three wells. However, there are slight variations in modelled and calibrated vitrinite data in the three wells, especially during the Cenomanian-Turonian period. These variations suggest the influence of additional localized heat flow during the Cenomanian-Turonian for the three wells. The hydrocarbon migration model suggests that vertical migration of gas began contemporaneously with generation from the central part as early as 108Ma. As at present day, Albian-aged reservoir remains only gas –prone while Cenomanian reservoir unit is also gas prone but with potential for oil westward (deep waters) .

A fault model constructed to test possible fault controls on migration pathways shows a syn-rift listric fault to be 100% gas saturated as at 93 Ma and lost its saturation by 65Ma, suggesting a breakthrough path through the listric fault which caused it to lose its saturation. The breakthrough path is linked to fault reactivation which enables further migration of gas; which is classical of a passive margin basin. Finally, the model reveals evidence of gas escape at the sea floor and there is no evidence of hydrocarbon accumulation in the study area.

Analysis of Petroleum System in Mahu Sag of Junggar Basin, Northwest China

Jian Wang, Zhuangxiaoxue Liu, Xiaozhi Wu, Jingdu Yu, Qiulin Guo
Petrochina Research Institute of Petroleum Exploration & Development

Mahu Sag is located in the northwest edge of Junggar Basin, it has been proved to be an oil-rich depression. The main oil and gas discovery strata are the Upper Paleozoic Permian to Mesozoic Triassic. A complete petroleum system is formed by Permian high quality source rock, Permian - Triassic fan delta glutenite, dolomite, volcanic rock and overlying thick mudstone[1]. Based on the study of petroleum system, this paper comprehensively reveals the accumulation conditions of oil and gas and the matching relationship in Mahu Sag, which will provide scientific basis for exploration.

1.1 Source Rock

The main source rocks in Mahu sag are mainly developed in the upper Paleozoic, including the lower Permian Jiamuhe formation, Fengcheng formation and the lower Wuerhe formation of Middle Permian. The Carboniferous is speculated to develop source rocks, but it has not been confirmed yet. During the Fengcheng formation sedimentation period, Mahu Sag was a restricted closed lake with shallow ancient water body. An alkaline lake was formed during the Fengcheng formation sedimentation period, with high water salinity and good preservation conditions. The forming of this alkaline lake is due to semi-arid climate conditions, which evaporation capacity is greater than supply capacity, and seasonal humid environment and arid environment alternate. The hydrocarbon-generating parent material is algae with high organic matter abundance, with an average TOC of 2.2 %. The parent material type is Ⅱ 1 - Ⅰ, and Ro is 0.85 - 1.4 %, mainly at the peak stage of oil generation, with a deposition center thickness of 450 m, which is the main source rock for the study area. The Lower Wuerhe formation was dominated by freshwater reducing environment, which was favorable for organic matter preservation and was a secondary source rock. The source rocks of Jiamuhe formation are mainly type III parent rocks with TOC content less than 0.74 % and limited hydrocarbon supply capacity.

1.2 Reservoir Rock

Since the end of Fengcheng formation sedimentation period, fan delta has developed on a large scale, especially in Upper Wuerhe formation of Permian. The Zhongguai fan, Karamay fan, Baijiantan fan and Dabasong fan are developed around the lake, and the favorable facies belt at the leading edge is over 2100 km2. The Triassic Baikouquan fomation developed large shallow water fan deltas such as the Zhongguai fan, Karamay fan, Huangyangquan fan, Wuerhe fan, Xiazijie fan, Hongqiba fan, Yanbei fan and Xiayan fan. The favorable facies belt of fan delta front covers an area of over 4300 km2 of the middle-lower slope area of Mahu sag, and develops glutenite favorable reservoir. The physical properties of reservoirs are mainly controlled by lithofacies, while the physical properties of glutenite in the favorable facies zone at the front edge have little relationship with burial depth, and are generally low porosity and low permeability. Dolomitic reservoir is mainly developed in Fengcheng fomation of Lower Permian, and its lithology is mainly dolomitic siltstone and argillaceous dolomite. Volcanic reservoirs are mainly developed in the Carboniferous - Lower Permian Jiamuhe Fomation and Fengcheng Fomation[2].

1.3 Sealing Layer

There are three sets of regional high-quality caprocks in the vertical direction in the Mahu depression area, lacustrine mudstone of the upper middle Triassic and middle Permian, and (dolomitic) mudstone of lower Permian Fengcheng fomation. Among them, Karamay formation - Baijiantan formation of Middle and Upper Triassic is lacustrine mudstone with a thickness of 500 - 900 m. A thick mudstone layer with a thickness of 300 - 1200 m has been developed in the Lower Wuerhe formation of Middle Permian. The mudstone thickness of Fengcheng formation is 200 - 1000 m, and the high-quality (dolomitic) mudstone caprock is mainly developed in the depression.

1.4 Conducting System

The Hercynian Epoch developed thrust faults, which broke through the Early - Middle Permian strata and controlled the formation of Middle - Permian reservoirs. Strike - slip fault developed in Indosinian period and broke through the Triassic and Late Middle Permian strata, becoming a large-scale migration channel for oil and gas to the Permian Wuerhe formation and Triassic Baikouquan formation. Yanshan fault inherited the characteristics of Indosinian fault and further adjusted the oil and gas upward. At the same time, the multi-stage unconformity developed from

Permian to Triassic, including Fengcheng formation, Xiazijie formation, Wuerhe formation and Baikouquan formation[3]. Oil and gas can be transported vertically and horizontally through oil-migrating faults, unconformities and delta front sandbodies. Faults developed during Himalayan period are inactive, oil and gas are further laterally adjusted within the trap, and the inactive faults play a lateral plugging role (Figure 1).

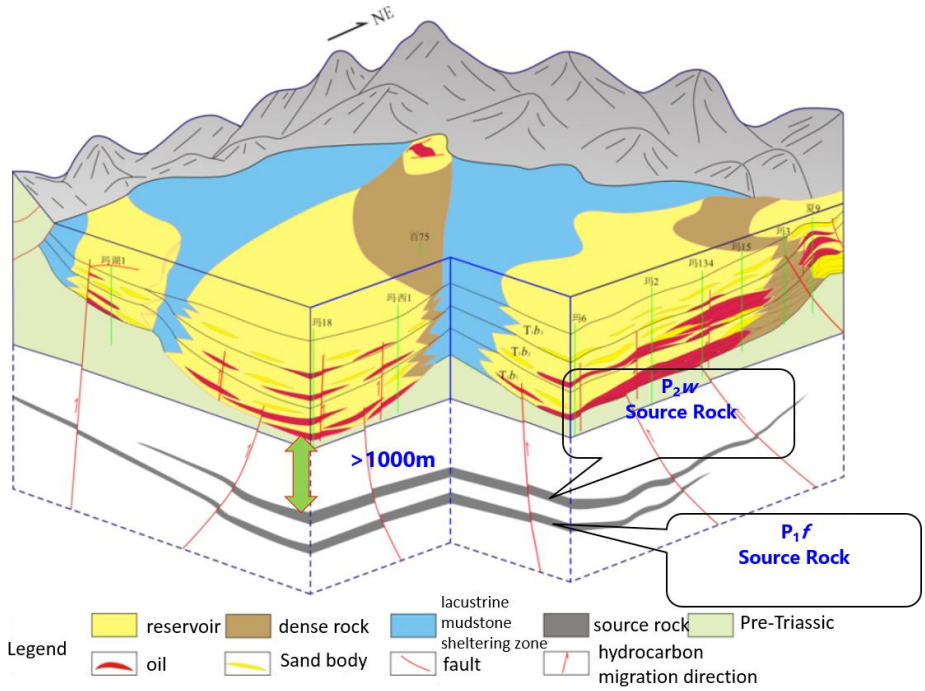

Figure 1 Reservoir-forming model of fan delta front in Mahu sag of Junggar basin.

In addition, Fengcheng formation itself is the target layer, and it is in overlying or lateral contact with Jiamuhe formation and Carboniferous. Therefore, large-scale glutenite reservoirs of "lower source rock and upper reservoir" combination can formed in the Permian Wuerhe formation and Triassic Baikouquan formation, as well as in the deeper layers.

Combining modelling dimensions, software and states of mind in PSA: an application to the Namibe Basin, off southern Angola

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Petroleum systems modelling-analysis (PSM-A) is based on physical (or physical chemistry) laws that govern where/when petroleum forms, migrates and resides (Downey, 2014). There is, however, much uncertainty in most modelled processes. In some cases, because we do not fully understand the first principles that control a given process (e.g. kerogen kinetics). In others, the data lacks the necessary resolution, or the hardware the required capability, to model the full extension of the process (e.g. petroleum expulsion and migration). Yet in others, because we lack sufficient/appropriate data to calibrate the models, such as in frontier basins.

Software developers are therefore challenged to create tools that help reducing the inherent uncertainty in PSM, and/or quantify the risk of hydrocarbon charge in a basin, play or prospect, such as stochastic analysis, common segment risk mapping, combining results from a large number of "inexpensive" simulations/emulations, and solving for multi-scale processes in self-consistent models. Petroleum systems analysts (or modellers), in turn, can also contribute to significantly improve the modelling efficiency and reduce the uncertainty, by devising strategies and workflows which are adjusted to a particular exploration scenario.

In this study, we demonstrate the use of combined 2-D and 3-D (map-based) basin and petroleum system modelling techniques to de-risk hydrocarbon charge in the frontier Namibe basin, a deepwater rift margin off southern Angola. The models are based on the high quality 2-D and 3-D Geostreamer seismic data acquired by Petroleum Geo-Services (PGS) in 2011 and regional geophysical constraints on the structure of the lithosphere and thermal regimes. The petroleum systems are then defined from analogies between the Namibe basin and the prolific Santos (conjugate margin - Brazil) and Kwanza (central-north Angola) basins, well identified in the seismic data, as well as geochemistry data available along the South Atlantic margins.

For the 2-D modelling we use TecMod-2D (GeoModelling Solutions - GmbH), which solves simultaneously for basin-scale (e.g. sedimentation, compaction, maturation) and lithosphere-scale (e.g. crust/lithosphere thinning, break-up, flexure, serpentinization) processes while iteratively fitting the stratigraphy along a seismic transect (Rupke et al., 2008); i.e. the model computes a thermal structure for the basin through time that is consistent with the burial history constrained from the seismic data. This is particularly advantageous in frontier basins, where there is only scarce (if any) information on the present and past thermal regimes.

The inferred thermal structure is then extrapolated to the whole of the Namibe Basin covered by the 3-D seismic data via 1-D pseudo-well models, that take into account the lateral variations in the structural setting and burial history of the margin. The 3-D modelling uses the map-based Trinity software (Zetaware, Inc.), which allows rapid simulations for variations in key model inputs, and is thus ideal to cover the large uncertainties in the structural-thermal evolution and sedimentation processes of a frontier basin, and thus the wide range of model possibilities. In general, the modelling results support a high likelihood of oil, and locally gas generation and expulsion, from different source rock horizons, in both the syn-rift and post-rift sections. The models also predict charge of numerous mapped structures, with the migration patterns and distribution of oil and gas accumulations strongly depending on assumptions on seals, migration losses, sediment facies and permeabilities, etc.

While using a variety of PSM software might add time and costs to a project (software licenses, staff expertise, setup/parameterization of models, etc), we argue that combining complementary modelling approaches, which are compatible within a given project scope and timeframe, may contribute to reduce the uncertainty in petroleum systems modelling. The methodology followed in this study, for example, is particularly suitable to de-risk hydrocarbon charge in frontier basins. First, we compute a solution (or solutions) for the basin thermal regimes through time, which is determined by an evolving rift geometry and is consistent with the burial history constrained from the seismic data. Second, we use the constrained thermal structure to compute a large number of maturity-

expulsion-migration-charge scenarios covering a wide range of model possibilities in a relatively unknown setting. Depending on the number and complexity of the tested 2-D and 3-D modelling scenarios the methodology followed here takes between a few weeks and a few months, and would ideally be phased, to allow integration of the modelling results into the knowledge of the basin and objectives of the study.

Assessment of the Golden Zone for the Norwegian Barents Sea through estimation of net erosion and petroleum system modelling

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In the past three decades, the hydrocarbon prospectivity has been enigmatic in the southwestern Norwegian Barents Sea as gas discoveries have dominated over oil. However, recent discoveries provide optimism for changing the region into a combined oil and gas province. Much attention has been paid to seal integrity, hydrocarbon loss and the possibility of titled traps and fairways redirecting migration of hydrocarbons due to the tectonic and glacigenic events that have taken place in the Norwegian Barents Sea. Owing to severe uplift and erosion, particularly on structural highs and platforms, it has generally been agreed that timing and magnitude of erosion can reach up to about 2500 m during Paleocene, Oligocene-Miocene and Plio-Pleistocene (e.g. Henriksen et al., 2011; Ktenas et al., 2017, in press).

PetroMod 2D basin modelling was performed across a regional seismic section crossing the southwestern Barents Sea. For calibration of the 2D model, 1D modelling was performed for a selected number of wells in the region. By integrating different erosion estimates from temperature and vitrinite reflectance data, sonic logs and velocity inversion, we aim to show how this is influencing the 'Golden Zone' for the southwestern Barents Sea as well as its impact on the petroleum system of the under-explored Finnmark Platform and the source kitchen down-dip.

The concept of the 'Golden Zone' was developed by Buller et al. (2005) and Nadeau (2011, and references therein), where the zone represents the majority of discoveries found globally in a certain temperature range of 60-120°C (Figure 1). This integrates temperature-controlling processes comprising of diagenesis of siliciclastic deposits and its impact on reservoir quality. The overlying Compaction Zone is characterised by mechanical compaction and the formation of sealing rock units. Below the 'Golden Zone', the Expulsion Zone is considered at larger temperatures as an important petroleum system element comprising a source kitchen generating and expelling oil and gas.

Furthermore, tectonic uplift and erosion events as well the ice ages with loading and de-loading of ice and the associated erosion are modelled in PetroMod 3D (e.g. Cavanagh et al., 2006; Nielsen et al., 2013, 2014) and are thought to have resulted in large fluctuations in temperature and pressure gradients in the sedimentary succession. Such large changes in pressure gradients and the high rates of hydrocarbon generation from source rocks have most likely promoted fluid flow and formation of gas chimneys and pockmarks with the associated leakage and loss of hydrocarbons excessing the seal capacity. The geologically sudden erosion and uplift events especially during the ice ages resulted in temperature disequilibrium and this decrease in temperature of reservoirs has shifted the 'Golden Zone' and the associated zones to a shallower depth (Figure 1).

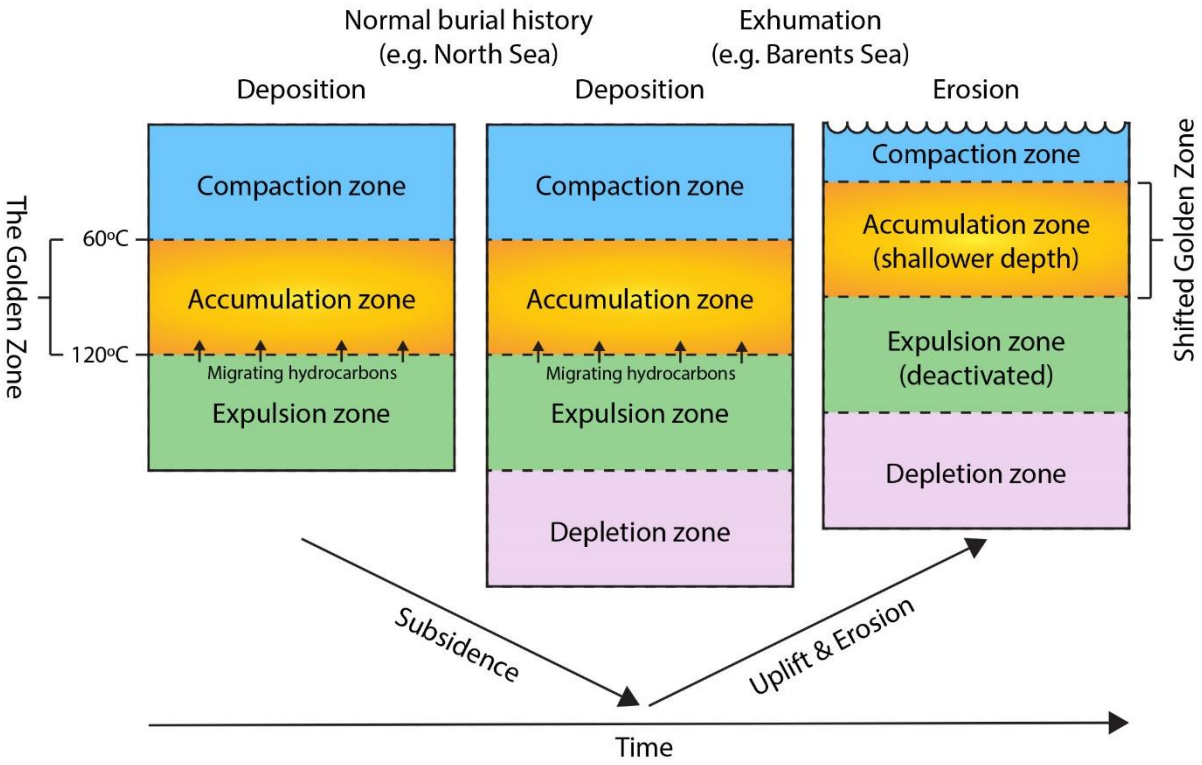

Figure 1. Concepts and mechanisms affecting the depth and the temperature expected for the Golden Zone. On the left side of the figure, sedimentary deposits subjected to normal subsidence are reaching their maximum burial depth at present day which is typically found for the North Sea, for example. On the right side of the figure, the major erosion events that characterise the Norwegian Barents Sea have shifted the Golden Zone to a shallower depth and a lower temperature.

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This Code of Conduct applies to all participants in Society related activities, including, but not limited to, attendees, speakers, volunteers, exhibitors, representatives to outside bodies, and applies in all GSL activities, including ancillary meetings, events and social gatherings.

It also applies to members of the Society attending externally organised events, wherever the venue.

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Burlington House
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If you hear the Alarm

Alarm Bells are situated throughout the building and will ring continuously for an evacuation. Do not stop to collect your personal belongings.

Leave the building via the nearest and safest exit or the exit that you are advised to by the Fire Marshal on that floor.

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Lower Library:
Exit via main reception onto Piccadilly, or via staff entrance onto the courtyard.
Lecture Theatre
Exit at front of theatre (by screen) onto Courtyard or via side door out to Piccadilly entrance or via the doors that link to the Lower Library and to the staff entrance.
Main Piccadilly Entrance
Straight out door and walk around to the Courtyard.

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Assemble in the Courtyard in front of the Royal Academy, outside the Royal Astronomical Society. Event organizers should report as soon as possible to the nearest Fire Marshal on whether all event participants have been safely evacuated.

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All accidents should be reported to Reception and First Aid assistance will be provided if necessary.

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Ground Floor Plan of the Geological Society, Burlington House, Piccadilly