Advances in Production Geoscience as an enabler for maximising economic recovery and ensuring a future for the UKCS

6-7 June 2018

Robert Gordon University, Aberdeen

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Wedneday 6th June 2018
Session One

KEYNOTE: Controls on the evolution and prospectivity of the North Sea rift system

John R Underhill,
Shell Centre of Exploration Geoscience, Applied Geoscience Unit, Institute of Petroleum Engineering, Heriot-Watt University, Edinburgh, EH14 4AS

The North Sea Basin recently celebrated its 50th year as a petroleum province. In that time, it has produced 43 billion barrels of oil equivalent leading to it being classified as a global super-basin. A notable strength of the basin is the sheer number and variety of play types with reservoir intervals spanning the whole geological record. Many elements of the North Sea's success are dictated by a transient phase of Middle Jurassic thermal doming that led to the development of Brent Group fluvio-deltaic reservoirs. Subsequent Upper Jurassic (syn-rift) extensional activity led to the creation of a trilete, failed rift comprising the Viking Graben, Moray Firth and Central Graben, in which the main Humber Group (Kimmeridge Clay and Heather Formation) source rocks were deposited. Syn-rift activity also created numerous tilted fault blocks trapping rotated and highly prospective pre-rift sequences in, and on the flanks of, the grabens (e.g. in the East Shetland Basin). Cretaceous-Recent (post-rift) subsidence led to maturation of, and migration from, kitchen areas in the grabens with resultant charge of the extensional fault blocks and their draping post-rift sequences via a mechanism of fill-and-spill. Post-rift subsidence was interrupted by convection-induced uplift and intraplate deformation, most notably on the Atlantic margin during the Early Cenozoic, which led to a down-to-the-east tilt and triggered deposition of major clastic reservoirs (e.g. the Forties Formation) in the North Sea. Basin exhumation proved to be highly detrimental to prospectivity in more westerly areas (e.g. Inner Moray Firth), where maturation was arrested, traps were breached and biodegradation took place. However, its effects diminished towards the east leaving the Viking Graben and Central Graben relatively unaffected and hence, explaining why they are the main contributors to the super basin's volumes.

NOTES:

Clair Phase 1 development wells A21-A25Z: Still learning important lessons in your early twenties

Mark Webster
BP

The Phase 1 area of the naturally fractured Clair field started production in 2005. 20 development wells were drilled in the period up to 2011, recovering over 115 mmboe to date. These initial wells provided key lessons on wellbore instability issues in the overburden and the variable productivity and connectivity of this complex reservoir.

After a five-year drilling hiatus, a diverse portfolio of 5 further development wells was planned, successfully drilled and brought online in 2016-17. A general improvement in drilling performance was delivered and static well results were within the predicted range, demonstrating that historic lessons had been learned; however a range of subsurface risk outcomes still occurred. Some events were predicted and some were not, highlighting that uncertainty and risk management is still a critical component of well planning and execution later in field life.

This talk covers the objectives and well results of the Clair Phase 1 development wells A21-A25Z; a candid reflection on the key pre-drill risks versus the well outcomes, and how these new lessons will be embedded for future Clair wells.

NOTES:

Maximising economic recovery from the Captain Field: infill drilling results from the 10th platform development campaign

David J. Moy[1], Jenny Windress[1], Alex Fraser[1], Iain Robertson[1], Matthew Maciocia[1], Daniel Bissett[1], Pablo Carnicero[1], Phil Brock[2], Jon Skillings[2] and Richard Tilsley-Baker[2]

[1]*Chevron Upstream Europe, Chevron North Sea Ltd, Chevron House, Hill of Rubislaw, Aberdeen, AB15 6XL, United Kingdom.*

[2]*Baker Hughes, a GE Company*

Producing for over 20 years, the Captain Field in the inner Moray Firth is a heavy oil field development of three reservoir intervals; the deep marine Lower Cretaceous-aged Upper and Lower Captain Sands ('UCS' & 'LCS') and the shallow marine Jurassic Ross Reservoir. Each reservoir is typified by relatively high net:gross, porosity and permeability, successfully developed through horizontal well technology from a Wellhead Protector Platform (WPP) and two subsea centres. To date, over 300 MMbbls of oil have been produced through waterflood of the reservoirs, but to enable the further recovery of unswept and bypassed oil, new technologies as well as focussing on optimising the development cost for drilling infill wells are needed to fully maximise economic recovery from the field.

Despite the downturn in price of crude oil, between 2016-17, the 10th platform development campaign further developed the UCS reservoir through four new infill wells and collecting surveillance data (injection logging) in 3 wells. This included the new C60 injector, the first well of the campaign, which has exhibited some of the highest injectivity performance in the field to date.

To enable the successful development of remaining oil, planning and execution requires a multi-functional team approach. Nowhere more so was this exemplified than on the C61 well located directly beneath the WPP'A' Platform, requiring a 350° 'corkscrew' azimuthal turn to access the target. Although the infill opportunity was proven through a strategic pilot in 2015, successful development required significant interaction between subsurface and D&C disciplines, overcoming a series of planning hurdles.

The outcome was aligned with the geological best technical case prognosis, and was successfully stimulated to enhance production rates from a short well in a preferentially elevated position of the reservoir. Production performance to date is aligned with mid-case predictions. Results such as these are key in proving to management and stakeholders that the asset can deliver the complex projects it promises, ensuring further long-term investment. The third well (C62) presented new challenges to the team as it required what is believed to be an industry first, removing a casing patch from a production well. Alternative selection, detailed planning and yard testing were key to the execution performance which exceeded P10 timings despite 24% non-productive time (NPT), and were incident free, ultimately enabling further development of the reservoir.

The final production well of the campaign (C63) was in an area of the field with significant reservoir uncertainty towards the field edge, despite many development wells present in this area. Using Logging While Drilling (LWD) azimuthal resistivity tools (Baker Hughes AziTrak™ and VisiTrak™ technology), the well was successfully geosteered close to the reservoir roof, maximising the available recoverable oil. However, around the uncertain reservoir edge, the well exited to shale. Influencing of management through geological reasoning, generated support for the team to continue drilling. Finally, using VisiTrak™ LWD technology, the reservoir sand was identified below the well path, allowing the well to be geosteered to confirm the presence and thickness of the oil bearing sand.

The well was subsequently side-tracked to enable the development of the toe sands, with the acquired LWD data enabling the team to aggressively geosteer in a relatively thin reservoir interval. Furthermore, the tool provided data during drilling of the sidetrack informing the team of the reservoir structure (interpreted as deepwater channel elements) which benefitted the geosteering strategy in this area, maximising well connectivity with the reservoir. Through technology and geology, the result has increased the estimated ultimate recoverable (EUR) of the well.

Data acquired from this development will also enhance the planning and execution of future Chemical Enhanced Oil Recovery (EOR) wells in this area of the field.

Key to all wells going forwards is maintaining the momentum we have gained during the 10th platform campaign. Identifying best practices and learnings that will benefit future infill opportunities, further optimising D&C time-cost estimates based on improved execution performance and embracing new technology are key to maximising economic recovery from the Captain Field.

NOTES:

Whose fault is it anyway? – effective communication between geologists and engineers.

Graham Yielding
Badley Geoscience Ltd, Lincolnshire, UK.

Intra-reservoir faults can have a significant effect on flow during production. The basic principles of how to represent geological faults appropriately in reservoir flow models have been known for many years. Since the fault rock (or fault core) is too narrow to represent as a distinct layer of cells, its flow effect is represented by a set of transmissibility modifiers at all the cell-cell connections. These multipliers reduce the flow across the fault relative to that which the simulator would calculate in the absence of fault rock – their value is calculated from the permeability and thickness of the fault rock together with the permeabilities and dimensions of the connected reservoir cells. Hence the transmissibility multipliers are engineering variables, not simple geological properties of the faults.

In siliciclastic sequences, the main controls on fault rock permeability and thickness are well understood. Types of fault rock include clay smears, phyllosilicate framework fault rocks, cataclasites and disaggregation zones. Their distribution on a fault plane can be predicted in a general (or probabilistic) sense from the fault displacement and stratigraphic architecture. Each type of fault rock has a range of permeability which depends on the faulting and burial history as well as its composition. Detailed fault rock structure is often complex, but the flow properties at the scale of a cell-cell connection can be readily averaged by appropriate upscaling.

A more challenging scale range to model is that just above and below seismic resolution. The smaller seismically-mapped faults are often left out of a reservoir model for simplicity, but this process may corrupt the topology of the fault network so that it becomes impossible to represent the true flowpaths in the faulted reservoir. Faults below seismic resolution may still have a significant flow reduction effect. Sub-resolution fault-zone structure (e.g. relay zones) may have the opposite effect, providing holes in otherwise sealing faults. Given that such fault-zone structures are observed to follow certain scaling rules with regard to their dimensions and aspect ratios, it is feasible to use stochastic modelling to populate the engineering model with additional small-scale geological structure in a representative way.

There remains a cultural obstacle to the implementation of the above methods in many companies. The common practice of assigning uniform transmissibility multipliers to fault surfaces in a flow model is unphysical, and corresponds to fault-rock permeability variation being dependent on the model layer thicknesses. Although such ad hoc multipliers might achieve an apparent history match there is little guarantee that they can provide a reliable production forecast. For effective management of faulted reservoirs, good technical communication between structural geologists and reservoir engineers is essential.

NOTES:

Delivering new opportunities in a mature hub through secondary reservoir appraisal: Mungo Chalk, Central North Sea

Hannah Patterson, Norman Laing**,** Greg Baniak, and Zoë Sayer.
BP Exploration Operating Company Limited, 1 Wellheads Avenue, Dyce, Aberdeen, AB21 7PB

The Central North Sea's Mungo Field comprises stacked Palaeocene sandstones and chalk reservoirs draped over a pierced salt diapir. Development to date has focussed primarily on the Palaeocene reservoir, leaving the underlying chalk reservoir poorly understood and underdeveloped. This now poses an exciting opportunity to assess its potential as a cheap to access secondary reservoir development at the centre of a mature hub.

A chalk appraisal well in 1998 delivered 4000 bopd, but this rate was considered disappointing at the time when compared to primary reservoir performance. Subsequent Palaeocene wells provided new chalk data and revealed many similarities to the nearby chalk-producing Machar Field. However, fracture presence, and hence chalk deliverability, remained a key risk. In 2015 an acid stimulation of an existing well delivered gross liquid rates of 12,000 bopd. This confirmed the presence of a natural fracture system and the potential of the chalk reservoir as an economically deliverable reservoir.

Encouraged by this success, detailed geological studies were carried out to improve the understanding of the spatial distribution of the fracture system and chalk facies. This has allowed the generation of a hopper of well opportunities. Further progression to drilling these relies on new data to be obtained from the Machar Field to reduce uncertainty in critical gas saturation and relative permeability. Understanding these parameters, coupled with improved seismic imaging of the reservoir, will help determine the economic viability of a Mungo chalk development.

NOTES:

Identifying connectivity and remaining targets in the slope channel turbidite reservoirs of the Schiehallion field, UK west of Shetland, through integration of 4D seismic, probabilistic inversion and production data

Noah Jaffey[1], Santaram Tata[2], Paul Reid[3], Konstantin Ryzhikov[1]
Affiliations: 1. Shell UK Ltd., 2. Chrysaor E&P Services Ltd., 3. BP Exploration Company Ltd.

The Schiehallion field, within Quad 204 is currently undergoing a major re-development which includes the installation of the new Glen Lyon FPSO and drilling of a 20 well campaign, which started in April 2015. This re-development plans to extend the life of the field until 2037 and enable an oil production rates of up to 130,000 bbl/day.

The field is located 150km west of the Shetland islands in water depth of ~425m. Reservoirs currently being developed include the T25, T28, T31 and T34 zones of the Vaila Fm., Palaeocene aged deep water deposits. The current interpretation of the reservoir depositional environment is of slope channel turbidites and channel-lobe transition zone deposits. The reservoir level is well imaged by seismic and has been the subject of seismic inversion and multiple time-lapse 3D seismic surveys acquired/processed during the fields ~20-year history. Schiehallion has one of the world's largest subsea infrastructures, with 76 wells drilled from 4 drilling centres.

The current development challenge is to locate and target the most significant accumulations of remaining oil and also to optimize the sweep of water from injector to producer wells. While simple models were adequate during early development, for the latest phase of development a suite of history matched dynamic models are required. To this end the Schiehallion joint-venture partners (BP operator, Shell, Siccar Point and Chrysaor) have integrated all available lines of evidence to re-assess the reservoir connectivity within the Vaila Fm. Reservoirs. This includes integration of data from oil geochemistry, biostrat based log zonation, baffles/possible flow paths identified from 4D seismic interpretation, injector-producer pressure response behavior, tracer data analysis, PLTs, fault seal evaluation and interference testing results during the Glen Lyon FPSO startup.

These observations have been compared with existing channel turbidite sedimentological models and analogues in an attempt to understand their geological cause and to predict connectivity behaviour away from wells. Learnings from these static and dynamic data have also been used to construct anticipated water flowlines to aid dynamic simulation (Fig.1).

Schiehallion is an example of a mature development in channel turbidites, where reservoir connectivity is well defined by ~20 years of high quality surveillance data. Reservoir connectivity surprises do occur however, and continued integration of multiple data streams provides insights into the location of flow baffles, barriers and high connectivity pathways. Insights from Schiehallion may be useful for predicting the connectivity of similar reservoirs at an earlier stage of development.

The extended Schiehallion development teams in all co-venturer companies are acknowledged for their contributions to this work, specifically including Julie Coughtrie, Jaume Hernandez (Shell) and Khuram Ilyas (Chrysaor).

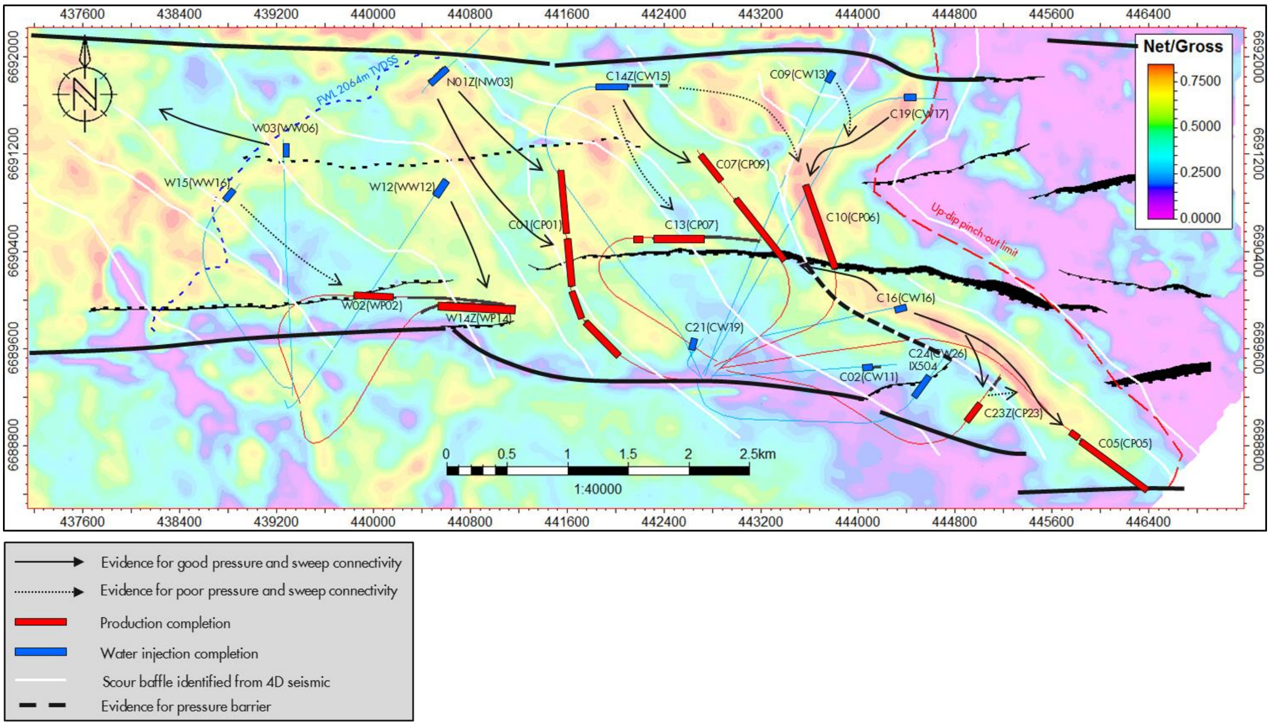

Figure 1: Average net-to-gross map showing interpreted baffles, barriers and high connectivity pathways within the Vaila Fm. T31 reservoir in Segment 1 of the Schiehallion field.

NOTES:

Wednesday 6th June 2018
Session Two

Hywind – The future is afloat!

Hannah Mary Goodlad,
Equinor

As a global energy provider Equinor develops oil, gas and energy solutions for today and tomorrow.

Equinor is founded on the principal that industrial development undertaken by skilful people should create value for society. The purpose is to bring energy to a growing population, to create value for the shareholders and the communities where Equinor operates. Equinor is guided by this as it works towards a future where energy is affordable and sustainable for all.

To succeed over time, the internal pace of change in any company must exceed the rate of change externally. And Equinor is no exception.

There are three identified areas importance for Equinor:
1. Equinor will produce oil and gas that the world needs competitively with lower greenhouse gas emissions.
2. Equinor will grow significantly within renewable energy with an ambition to invest around 15% of total CAPEX by 2030.
3. Equinor will actively stress-test the business to ensure competitiveness in a low-carbon future.

Equinor has created substantial value and has contributed to the development of society for almost 50 years. Today Equinor delivers energy to more than 170 million people and the company has the clear ambition to increase this number.

And in the in the UK, Equinor is active. In 1978, the company became a gas supplier to the UK market and now Equinor provides just over a quarter of the total UK gas supply. 2012 saw the step-change year for Equinor as the company gained operatorship of the Mariner oil field - the largest UK oil development in the last decade.

Equinor has also risen to the challenge of “maximising the economic recovery” for the UK hydrocarbon industry by chasing stranded oil and gas opportunities along the UK/Norwegian border line. There will come a day when none of the traditional sources of generating energy will apply. But that day is not now. The market is not there yet. Resources will continue to be developed. Equinors job is to ensure this is done: responsibly, safely and sustainably.

As a company, Equinor’s skill-set has been shaped by years of operating in the hostile offshore conditions that come hand in hand with the hydrocarbon industry. There are now clear opportunities enabling the company to harness that skill set and transfer it to the offshore renewables industry. Equinor terms it “technology in transition”. Equinor is committed to the full energy mix and that is why the portfolio is diverse and growing.

With shallow waters, strong bedrock and close proximity to Norway, Equinor chose the UK as an arena for developing its offshore wind business.
Currently in the UK, Equinor is operator of three windfarms, providing energy to just over 650,000 households. And with the Doggerbank project (the world’s largest undeveloped offshore wind project) maturing, Equinor is on track to potentially providing 3-4 mill households with renewable energy in the future.

Equinors offshore wind portfolio includes the innovative Hywind Scotland Pilot Park. Hywind Scotland is the world’s first floating windfarm, with five floating turbines based 25km off the coast of Peterhead. It uses proven and tested oil and gas technology, applied to a new context. It is believed to be a game changer for offshore renewables industry - enabling Equinor to chase deeper waters and higher winds.

If Equinor can get this on a competitive cost level with other energy sources, Hywind technology could contribute to energy security for many countries that need the energy supply locally, but do not have sufficient space onshore for solar or wind development. The learnings from Hywind Scotland will pave the way for new global market opportunities for floating offshore wind energy.

Equinor believes a low carbon footprint is a competitive advantage, providing the company with attractive business opportunities in the transition to a low carbon future.

NOTES:

Delivering value to producing fields using 4D seismic

Jon Brain,
Geophysicist, Shell UK LTD

Time-lapse seismic reservoir surveillance is a proven technology for offshore environments. In the past two decades we have seen this technology move from novel to necessary and enable us to monitor injection wells, water influx, compaction, un-drained fault blocks and bypassed reserves. Time-lapse seismic technologies have delivered more than a billion $(USD) of value to Shell fields around the world. Value is generated by influencing the management of our field operations and optimizing wells to reduce cost, accelerate production, and increase ultimate recovery. In this talk we will look at how this technology is applied in different regions, water depths, and geology and future advances we are working on to lower acquisition costs to enable more frequent monitoring.

NOTES:

Controlled Source Electromagnetics and Seismic associated with fluid escape structure in the northern North Sea

Yilo, N.K.[1], Gehrmann, R.[1], Böttner, C.[2], Berndt, C. [2], Bayrakci, G.[1], Minshull, T. A[1]. , Bull, J.[1]
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[2]*GEOMAR, Wischhofstr. 1-324148 Kiel, Germany*

Several geophysical studies in the Northern North Sea have revealed vertical anomalies in seismic reflection data, referred as chimneys or pipes, which have been associated with possible pathways for fluid flow. It has been inferred that fluids from deeper strata have migrated through these structures over geological time. At some of these structures, methane gas is expelled through the seafloor and observed in the water column. Seismically imaged chimney structures thus pose a potential risk for Carbon Capture and Storage (CCS) sites if the chimney structure permeability is high enough and the CO_2 reservoir seal is broken.

In April 2017 a controlled source electromagnetic (CSEM) and reflection seismic survey were completed in the UK North Sea at the Scanner Pockmark complex, an area underlain by widespread shallow gas, during cruise MSM63 (EU Horizon 2020 project STEMM-CCS). The seismic and CSEM experiments targeted a vertical fluid conduit identified in seismic reflection data (a “gas chimney”) that may be related to the active gas seepage at this pockmark.

The CSEM data were acquired with a Deep-towed Active Source Instrument (DASI) powered from the ship with a deep-tow cable and towed 20-40 m above the sea bottom across an array of multicomponent receivers. The receiver array was composed of: a) 14 free-fall ocean bottom electric (OBE) field receivers, placed in contact with the sea bottom (2 and partially 3 components of the electric field), and b) two three-axial Vulcan receivers towed behind the source. Figure 1 shows the schematics of the survey setup.

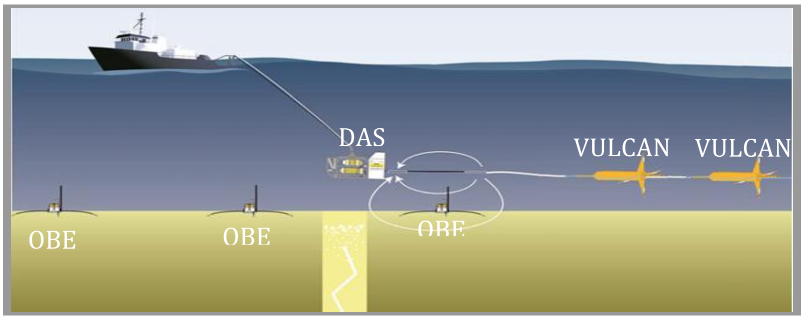


Figure 1 *University of Southampton towed CSEM system showing the electromagnetic source DASI, the dipole transmitting antenna (white lines represent current streamlines generated by the antenna), the three-axis electric field towed Vulcan receiver and three-axis ocean bottom electric field receivers (OBE).*

The CSEM survey was carried out in water depths <150 m, with the source towed along 12 profiles, in a star pattern over the chimney to cover 4 azimuths for anisotropy analysis. The 14 ocean bottom instruments were equipped with two orthogonal horizontal 12 m electrodes. Six instruments were equipped with vertical 1.5 m electrodes, as the effect of the signal propagating through air is less prominent in the vertical component than in the vertical component

During cruise MSM63 seismic reflection data were collected using GI guns, and this source was recorded on 18 Ocean bottom seismometers (OBS) around the Scanner pockmark. In September 2017 a broad band seismic anisotropy experiment was carried out around the same area (Scanner pockmark) funded by NERC (CHIMNEY project). This time data were collected using GI-guns and multichannel streamers covering all the CSEM profiles acquired during the MSM63 cruise.

We will present CSEM data acquired during MSM63 and discuss the preliminary interpretation of the electrical resistivity of the subsurface and how this relates to the geological processes by integrating it with the preliminary reflection seismic results from the data collected during the April and September 2017 cruises.

NOTES:

Reservoir characterisation improvements, Cambo field, West of Shetland

Christian Ellis, Heather Poore, Andy Alexander, Katie Overshott, Kevin Purvis.
Siccar Point Energy.

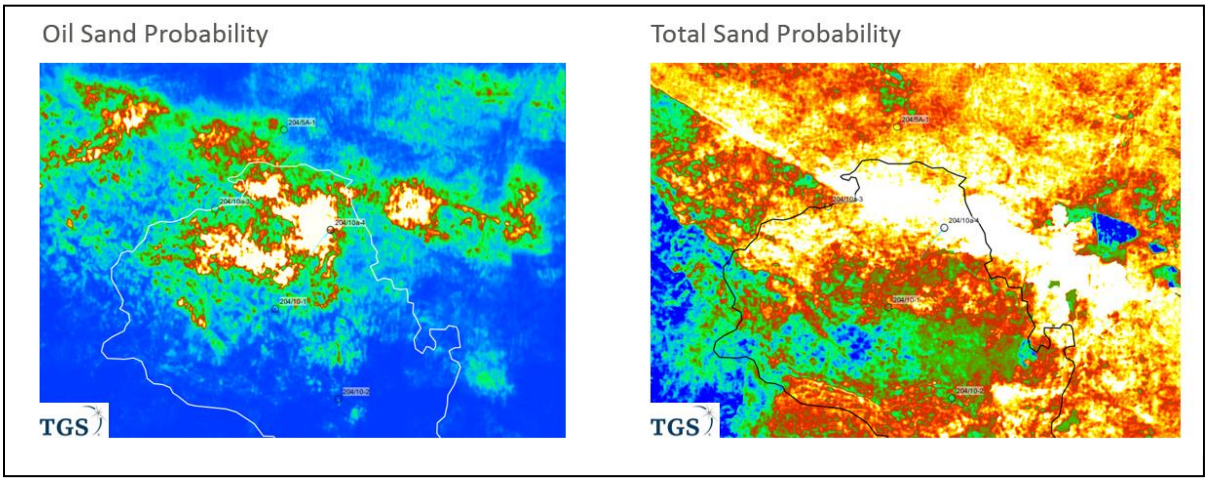
The discovery of the Cambo oil accumulation in 2002 was just four years after the resolution of the white zone disagreement between the Faroese and UK governments. Four wells have been drilled within closure, confirming a STOIIP of the order of 0.6 – 0.8 billion bbl, which is currently the focus of a phased development by Siccar Point Energy.

The proposed development is supported by dual azimuth (DAZ) broadband seismic data. Multiple stacked sandstone reservoirs are separated by thin coals and shales, all within seismic tuning thickness. Rock physics modelling shows that oil versus brine sand separation can be subtle for the main Palaeocene Hildasay reservoir complex. Although imaging is excellent, quantitative reservoir characterisation has required a sustained QI campaign over several years.

Simultaneous AVO inversion of the first (N-S) azimuth in 2014, has been followed up in 2017 by EEI and stochastic inversion of the combined DAZ data. The different inversions were carried out by different contractors, working closely with the operator, and they are complimented by in-house elastic inversions. We draw on the results from all the inversions, and use them to highlight key parameters of the field, critically hydrocarbon versus brine, and sand versus shale distributions.

Despite the tuned nature of the seismic and the important role of coals on the reflectivity model, there is a remarkable correlation between hydrocarbon probability from inversion with known penetrated hydrocarbon columns (apparently if greater than a certain threshold thickness). In addition, seismic stratigraphic observations of differential compaction appear to support, at least in part, increased sand probability from the inversion products. Integration of all these observations has led to improved confidence in delineating reservoir distribution, reservoir characterisation and therefore well placement. It is anticipated that the inversions will be used to help constrain the optimal placement of water injectors with regards to communication with producers. Further optimisation and improvement of the inversion schemes will become possible as new data are recorded from the early wells.

Figure 1 – Inversions to Oil Sand greater than a critical threshold thickness (but not in thinner penetrated HC columns), and Total Sand, Hildasay reservoir. Input reflectivity data courtesy of TGS.



NOTES:

KEYNOTE: The North Sea is 'dead', 'long live' the North Sea

Jon Gluyas
Durham Energy Institute, Durham University, Durham DH1 3LE

The quote in the title is normally reserved for monarchs to emphasize that while one may die there is an heir ready to maintain continuity within the kingdom. The reason for choosing to borrow and misuse the quote in relation to the petroleum province of the North Sea and adjacent areas is because production of petroleum from the North Sea underpinned UK national economic and energy security since the late 1960s. Moreover, it could do so for many years to come but maintaining such 'national capability' will require substantial investment. Business as usual will not deliver the change needed to 'maximize economic recovery'.

Even after 50 years of petroleum production the resource base of the North Sea remains large. Overall, <50% of the oil in discovered fields has been recovered. In addition, enhanced gas recovery and development of discovered but unproduced tight gas fields is perfectly feasible.

Petroleum is not the only asset in the North Sea basins. Hot water, solutes and associated gases could also have value but as yet their economic worth has not been fully assessed. These fluids may have considerable value as has the pore-space from which they are extracted. Geostorage of carbon dioxide and other fluids that might otherwise contaminate the Earth's surface or atmosphere can take place in the pressure-vacated pore space.

Without UK government intervention it is unlikely that the petroleum and other resources will become reserves. National capability will be compromised and with it the economic and energy security of the UK.

NOTES:

Thursday 7th June 2018
Session Three

KEYNOTE: Innovative geoscience and private equity - the key to unlocking stranded assets: Siccar Point Energy case history

Iain Bartholomew
Siccar Point Energy

The collapse in the oil price in 2014 put numerous field developments and exploration drilling projects in the UKCS on hold. Deal flow between companies also stalled with very few material transactions taking place.

The end of 2016 was a key turning point and by 2017 deal flow had significantly started up again. In the first 9 months of 2017 ~$20 billion was spent on North Sea deals with ~$10 billion coming from private equity and most of the rest from Maersk's $7.5 billion sale to Total. The 'Majors' and 'Utilities' have been the primary sellers. The fundamental change in the market that the private equity investors had latched on to is that the larger companies, after the crash in the oil price, were willing to consider selling equity in material assets with a long remaining field life, that still required near-term capital investment: something that would have hardly been contemplated in the previous $100 per barrel world. Siccar Point Energy's acquisition of OMV (U.K.) was the first material private equity transaction with many others following.

The key driver for a private equity investor is to deliver a high multiple on invested capital at exit as quickly and as efficiently as possible. The most effective way of creating value is to acquire a portfolio that requires short term capital investment to deliver the required returns.

Following their acquisition from JX Nippon and the purchase of OMV (U.K.), Siccar Point Energy has created a portfolio of assets that require short term capital investment. These include non-operated shares in material fields with long remaining field life (Schiehallion (on stream); Mariner (in development); and Rosebank (coming up for development decision)); operated development opportunities (Cambo and Suilven); and a material high quality West of Shetlands exploration position with eight out of nine licences operated.

As part of the OMV (U.K.) acquisition Siccar Point inherited an exceptional regional knowledge of the West of Shetland area. New innovative regional geological thinking, particularly in igneous geology, combined with excellent quality 3D seismic data have given confidence to unlocking valuable investment opportunities in the area. This is particularly the case in the Corona Ridge area which contains the Rosebank and Cambo undeveloped fields, as well as numerous exploration opportunities. Investment in these opportunities will now proceed with the backing of private equity funding.

Siccar Point Energy is now in a major capital investment programme including: ongoing Schiehallion drilling; Mariner development with first oil in late 2018; Cambo appraisal well with long term test prior to a FDP decision; and two committed exploration wells in West of Shetland area (Lyon in 2018 and Blackrock in 2019).

The private equity model of acquiring and then investing is providing an injection of new capital into the North Sea. This should accelerate the development of stranded fields and stimulate renewed exploration activity. Siccar Point Energy is already playing a key role in this new activity.

NOTES:

March of the Penguins- The Journey to Redevelopment

Ritchie, L.J., **Thorpe, D**., Porter, M.
Shell U.K. Limited

The Shell-operated Penguins cluster (50% Shell/ 50% Esso) is situated 55 km to the north of the Brent Field in the UK Northern North Sea. Discovered in 1974, the cluster comprises five separate, Jurassic and Triassic age, oil and gas fields (A-E). Since 2003, four of these (A, C, D and E) have been produced by 9 wells from 4 drill centres, through a commingled fluids pipeline tied back to the Brent Charlie platform. The fields continue to produce until the cessation of production of Brent Charlie at which point redevelopment of the Penguins cluster will be achieved by drilling 8 additional wells and connecting these along with existing wells, to a local FPSO hub.

Given the significant industry challenges of the last few years, this paper focuses on some of the key enablers that delivered the project to Final Investment Decision (FID). Principally these involved the acquisition and interpretation of Broadband seismic data which generated additional volumetric opportunities as well as refining and optimising additional targets. Furthermore, competitive scoping of the proposed subsea infrastructure realised a significant cost saving through simplification.

NOTES:

Analysis of fault leakage risk for offshore CO_2 storage sites on the East Irish Sea Basin, UK

Davide Gamboa[1], John D. O. Williams[2], Michelle Bentham[2], David Schofield[3], Andrew Mitchell[4]
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[4] *Geography & Earth Sciences, Aberystwyth University, Ceredigion, SY23 3DB, UK*

Carbon Capture and Storage (CCS) is a key technology towards a low-carbon energy future and will have an important role on the economic future of the UK Continental Shelf (UKCS). The East Irish Sea Basin (EISB) is a prospective area for CCS in the western UKCS, with a CO_2 storage potential to store over 1.7 Gt in hydrocarbon fields and in saline aquifers within the Permo-Triassic Sherwood Sandstone Formation and Lower Permian Collyhurst Sandstone formation. 3D seismic data were used to map in the detail the structural framework of the deformed post-Carboniferous successions of the EISB. Two main structural domains are present: a Northern domain with NW-SE faults, and a Southern domain with faults following a N-S orientation. Faults trending E-W are scarce but present in both domains. The basin compartmentalisation is variable. Lower degrees of compartmentalisation occur on the Northern domain where larger, widely spaced faults have developed. These predominantly detach or terminate along Upper Permian salt units. The greater degree of compartmentalisation is in the Southern domain, expressed by numerous rotated blocks bounded by closely spaced faults. The 3D fault framework was used for stress modelling and to assess the potential risk of CO_2 leakage in the basin. Stress orientations and magnitudes were obtained from published literature and available borehole data. Analysis of borehole breakouts were observed in four approximately vertical wells in the EISB suggest a maximum horizontal stress orientation of 155±10°. Calculations derived from well data indicate vertical stresses in the target intervals of interest for CO_2 storage between 18 (Triassic) to 40 MPa (Permian), for pore pressures between 9 and 18 MPa. Under regional stress conditions, easterly-dipping faults show increased slip tendencies, especially within shallower intervals. However, slip tendency values were predominantly below 0.6 (the theoretical value for onset of failure) at depth, suggesting the presence of stable structures in the EISB. Regional stress modelling of faults adjacent show a limited tendency for fault reactivation, capable to retain increase of pressure of 9 to 14 MPa before the onset of slip. The results suggest that leakage risks for CCS operations in the East Irish Sea Basin are limited.

NOTES:

The contrasting worlds of CO2 Storage and Petroleum Production Geoscience – Stories from a poacher turned gamekeeper

Alan James
Plae Blue Dot Energy

Targeted geoscience effort is a key requirement of both CO2 Storage and petroleum production. Both have a detailed reservoir focus, both involve two phase flow through natural geological formations of a porous and permeable nature and both are essential to support to business, commerce and society. Petroleum production geoscience supports the provision of affordable energy to the high carbon economy and industrial development. CO2 storage geoscience supports the delivery of a cost effective energy transition into a low carbon economy of clean industrial growth leading to the largely decarbonised world signposted by the Paris Agreement.

The world already has more than enough proven oil, gas and coal reserves. Recent work suggests that less than 25% of that proven reserves base can be produced and burned unabated if the world is to meet its 2 degree commitment under the Paris Agreement, a limit which is now anticipated to be reached by 2050 after which no unabated carbon fuel use will be possible. With the preferred and even lower 1.5 degree warming limit that leaves just 17 years at current rates of emissions.

“The UK’s Maximising Economic Recovery strategy contains a number of key Safeguards. Critically, the Central Obligation and the required actions and behaviours must be read subject to those safeguards. Specifically, “No obligation imposed by or under this Strategy permits or requires any conduct which would otherwise be prohibited by or under any legislation, including legislation relating to competition law, health, safety or environmental protection” such as for example the UK’s ratification of the Paris Agreement in 2016.

In order to fully monetise the existing proven petroleum reserves, reserves upon which bank loans will or have already been arranged, the oil and gas industry has no choice but to engage much more deeply with carbon capture and storage development. Not to simply manage minor operational emissions, but to mitigate the major emissions arising from the customers use of the industry’s primary product – petroleum. This paper outlines some of the key similarities between CO2 Storage geoscience and Petroleum Production geoscience and critically some of the fundamental differences where new industry practice is being developed.”

NOTES:

KEYNOTE: Decommissioning - A Geologist's perspective

Al Tucker
Shell

This paper examines some of the common challenges in late life field operation and the transition into field decommissioning for a mature oil field. The paper focusses on the role of the geologist in this process in the design, planning and execution of the well abandonment program. Additionally it illustrates the benefit of integrating both the late life operation and decommissioning phases of field life.

The paper uses a fictitious example to illustrate these challenges although these examples are drawn from real life operations. The objective is to share an operator's perspective of this phase of operation and through the use of an example economic forecast it examines how value can be created and destroyed by the decisions and investments made over this period.

NOTES:

The Role of Production Geoscience in an Integrated & Streamlined Approach to Well Abandonment Planning

Nicola Stewart[1], Ryan Singlehurst-Ward, Kate Smout, Folawole Sanwoolu, Manoochehr Salehabadi, Tharini Thirukkumar, Andrew Colman, Sadegh Taheri

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Due to economic and technical constraints, an appreciable number of North Sea oil and gas fields are projected to cease production within the following decade. After maximising recovery from these reservoirs, field decommissioning plans will be carefully examined to ensure minimal environmental impact is achieved at an acceptable cost to operators and UK tax payers.

Well Plug and Abandonment (P&A) is a key aspect of decommissioning activity. This must be planned such that the long-term risk of hydrocarbon release from reservoirs and overburden formations is mitigated without introducing over engineered execution scope and whilst abiding by industry standards and guidelines. Meeting these objectives repeatedly across a portfolio of late-life assets, each presenting various subsurface challenges, has required a streamlined and systematic approach.

Shell UK presents the workflow for formulation of a 'Subsurface Isolation Strategy', which has been developed to generate robust well abandonment plans in an accelerated timeframe (Figure 1). This is an integrated approach with Production Geoscience being a vital central component. It considers on a field-wide basis well completions, caprock integrity, overburden geology, reservoir pressure recharge and the configuration of previously abandoned wellbores in the field(s) of interest.

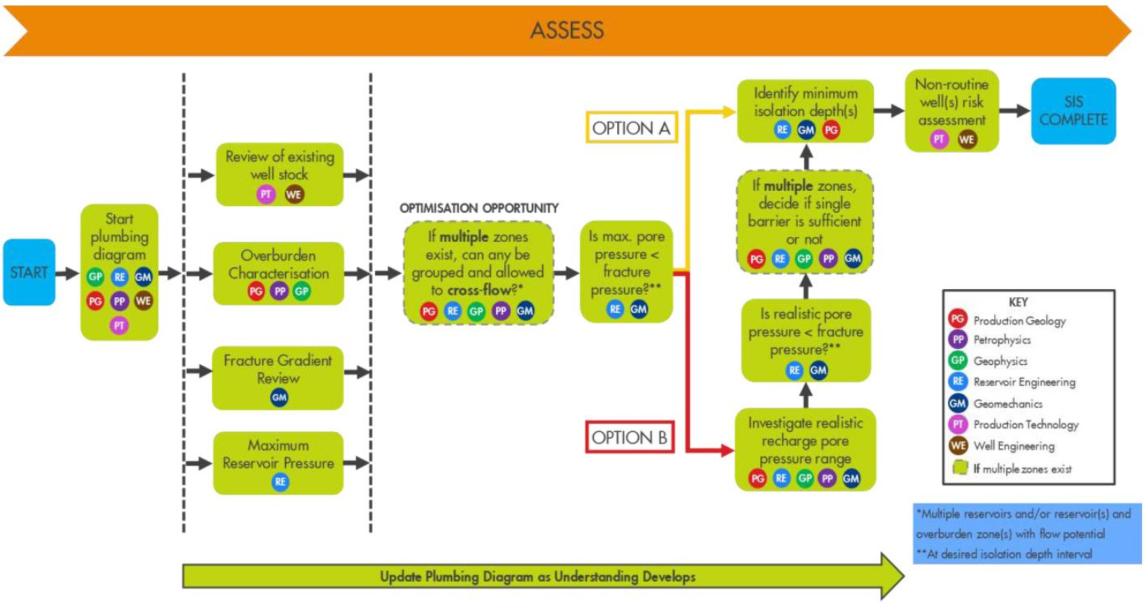

Figure 1: Integrated workflow for development of a Subsurface Isolation Strategy advances in production geoscience as an enabler for maximising economic recovery and ensuring a future for the ukcs

The integration of Production Geoscience with other subsurface disciplines in the approach outlined in this workflow has proven to facilitate a more comprehensive understanding of P&A execution risks and subsurface exposure post-abandonment allowing for more efficient delivery of lean isolation strategies. For Shell UK, this has also resulted in significant reductions in HSE exposure and cost through optimised P&A design and has permitted further savings to be pursued in subsequent execution design. It is anticipated that exposition of this process will assist operators in identifying and minimising the key subsurface risks associated with reservoir isolation in a more efficient manner and help to achieve further potential cost savings for the industry.

NOTES:

EOR in a Mature Fractured Reservoir: Machar Blowdown Preparation and Start up

Zoë Sayer, Jonathan Edet and Rob Gooder
BP Exploration Operating Company Limited, 1 Wellheads Avenue, Dyce, Aberdeen, AB21 7PB

The Machar Field comprises Chalk and Palaeocene sandstones draped over a high-relief salt diapir. The field has been produced via waterflood since 1998 and has been in decline since 2001. In order to maximise oil recovery and extend the field's life, Machar is entering a new phase of production via blowdown in early 2018, whereby water injection is turned off and the reservoir allowed to depressurise.

Waterflood in Machar Chalk, the main reservoir, has taken place through spontaneous imbibition. Injection water flows through the fracture system and is taken up by the microporous matrix, expelling oil into the fractures from where it is produced. Production to date has required a delicate balance between pressure support and offtake to prevent water short-circuiting through the fracture system. Modelling indicates that stopping injection and allowing the pressure to drop will cause expansion of gas within the pore spaces, which will force unswept oil into the fracture system to be produced until critical gas saturation is reached when gas will become the mobile phase.

The lack of analogues and relatively unique lab results have left many residual uncertainties, in particular critical gas saturation, which is a major factor for the expected oil recovery, relative permeability to water during blowdown, the potential to reactivate faults and differential compaction affecting wellbores. Pre-blowdown modelling of reservoir behaviour and compaction scenarios will be coupled with early well surveillance and bathymetric monitoring in order to understand the processes at play during blowdown.

NOTES:

Thursday 7th June 2018
Session Four

KEYNOTE: The future of Equinor in the UK and Ireland

Nigel Gamblin,
Equinor

Equinor, formerly Equinor, has a long history in the UK, commencing gas supply from Norway in 1978. However, our footprint has grown and we are proud to play an increasingly larger part as an energy partner to the UK. We are still active in our export of gas from Norway, currently supplying around 20% of the UK demand – in addition we have chosen the UK to be a hub for our offshore wind business. However, the biggest step change in the UK for Equinor came with us becoming an operator on the UKCS.

In 2012 Equinor sanctioned the Mariner oil field, one of the largest investments on the UKCS in the last decade. Once in operation, Mariner will support 700 long term jobs in the UK and create ripple effects in the local supply chain throughout its 30-year field life. Success to us will only come if we complete our work without harming our people or the environment. We are committed to safe and reliable operations in the North Sea and work hard to ensure every individual working on Mariner understands the mandate they each hold to ensure safety always comes first.

For Equinor, it's clear the North Sea is our back yard. We understand the reservoirs, the plays, the traps and we are now applying this knowledge to the UK side of the basin. We are now one of the most active explorers on the UKCS with the firm belief that significant discoveries are still to be made here. Last year we were pleased to announce a new discovery within the Verbier prospect in the outer Moray Firth on the UK Continental shelf which could hold between 25 and 130 million barrels of oil.

We are also putting a “One North Sea” approach into practice, treating the North Sea as “one basin” – rather than two separate margins. This “One North Sea” approach enables us to support the UK's objective of maximising economic recovery – through this strategy we are unlocking the potential of stranded fields by using existing infrastructure in the basin.

Our business here plays an important role in strengthening our international portfolio and Equinor sees many benefits to being in the UK. Secondly, the UK offers an excellent supplier base with a highly skilled and capable workforce. To date we have invested over £1 billion in contracts to UK based suppliers, and we are very pleased to have been able to recruit a strong team.

As well as being an upstream operator, we have also located the majority of our offshore wind portfolio here in the UK. Equinor now operates the Sheringham Shoal and Dudgeon windfarms, off the coast of Norfolk.

In addition we have Hywind Scotland, the world's first floating windpark. Hywind Scotland is a pilot park of 5 floating turbines which produce energy for around 20,000 homes. It will test the commerciality of this new technology, and if successful, has the potential to open up vast new markets around the world in deeper water areas. Our offshore wind business currently provides clean power to around 650,000 homes in the UK, and we have intentions to grow even more with our interest in the Dogger Bank project.

NOTES:

Delivering the Catcher development wells: A case study in reducing risks while successfully drilling a complex injectite reservoir

Steve Kenyon-Roberts[1], Dominic Riley[1], Matt Gibson[1], Cuong Nguyen[1], Tom Martin[1], Michael Bower[2], Ferdinando Perna[2], Amarjit Bisain[2], Xu Chong Hui[2], Joseph Wilding Steele[2]
[1]*Premier Oil UK*
[2]*Schlumberger*

The Catcher area development in the central North Sea comprises three Tertiary injectite fields where the reservoir is notable for being thin (always below seismic tuning thickness), of complex irregular geometries and with potentially significant depth uncertainties. Development drilling in these fields started in 2015, with drilling operations continuing non-stop since then. By the end of 2017, 33,000ft of gross reservoir section had been drilled and completed in 14 development wells. Drilling will continue well into 2018. Despite pre-drill concerns about potential pilot hole or sidetrack costs associated with placing the development wells in such a complex reservoir (based on historical data), to date, all the wells have been drilled without the need for either a pilot hole or a sidetrack, and the wells have exceeded expectations in terms of the net reservoir length penetrated by the well-bore. This has led to significant cost savings in the drilling campaign.

To help de-risk the particular challenges posed by this reservoir, Premier Oil has utilised the Schlumberger “Geosphere” Deep Directional Resistivity (DDR) logging while drilling tool to map and to help understand these complex injectite reservoirs. With a depth of investigation of up to 30m (100ft) TVD from the wellbore, the service has enabled the integrated Premier Oil and Schlumberger Well Placement team to map the injectites complex external geometries and internal architectural features in real-time. Being able to resolve the form of the injectite reservoir in real-time has provided the team the ability to use this wellbore-to-reservoir scale information to tie the position of the reservoir to the seismic data. From this it has been possible to forward project well-paths and make informed geosteering decisions. This ability to map and proactively geosteer, both on landing and within reservoirs in real-time, has helped Premier Oil to develop working practices and strategies to avoid pilot holes and geological sidetracks while optimising reservoir placement.

The presentation will describe case studies drawn from Catcher development drilling that demonstrate how the use of this DDR technology has enabled the elimination of a pilot hole, avoidance of possible sidetracks during the horizontal reservoir sections and improved reservoir contact in the development wells.

NOTES:

The Mariner Field: more than thirty years in the making

Matt Brettle
Equinor, Prime Four Business Park, Kingswells, Aberdeen, AB15 8QG.

The Mariner heavy oil field is one of the largest offshore developments in the UKCS in more than a decade. It is located on the East Shetland Platform in UK block 9/11 area some 320 km to the north-east of Aberdeen and 150 km east of the Shetland Isles. It was first identified on 2D seismic data acquired in 1977, and the 9/11- 1 discovery well was drilled in 1981 – which discovered heavy oil in both the Heimdal Sandstone Member (12°API & ~500cP viscosity) of the Lista Formation and the Maureen Formation (14°API & ~70cP viscosity). Over the subsequent thirty-seven years the Mariner Field has been subject to several development studies and concepts by different operators. Equinor has put forward a development concept that addresses the complexities of the field, in particular related to the production of heavy oil, the seismic imaging of Heimdal Sandstone Member reservoir, long term reservoir management, and project execution.

Development drilling commenced late in 2016, following installation of the platform jacket. Drilling continued until the start of hook-up and commissioning of the top-sides in June 2017, will recommence late in 2018, and first oil in anticipated by the end of 2018. At the same time as the 2016-17 development campaign, two appraisal wells, and a sidetrack were drilled. The application of learnings from these wells has proven useful in the planning of the main drilling campaign development wells.

Initial development drilling will focus on the Maureen Formation, where 20 oil producers and 5 water injectors are planned/ in the process of being planned. The gross-depositional setting of the Maureen Formation was a submarine slope, with the main Maureen reservoir fairway being deposited in an antecedent canyon system, which gradually filled and over spilled with sand. After deposition the Maureen was affected by sediment remobilisation and sand-injectite processes. The Maureen comprises approximately 16% carbonates lithofacies in two forms: mixed sand - reworked chalk lithologies and marl lithologies. The mixed sand – chalk lithologies were deposited by debris flow (clasts of chalk are observed as being greater than several metres in size) while the marl-lithologies were probably deposited in a mixed weak-turbidite/ suspension deposition. The age of carbonate component is dated as Maastrichtian, and it is considered as being cannibalised from up depositional slope. Prior to the 2016-2017 development drilling the Maureen Formation was considered as a dominantly "tank-like" sand. Correlation between carbonate identified on well-logs in the upper part of the Maureen reservoir and seismic amplitude of the same mapped horizon was used to predict the likely location of carbonate in the topmost part of the Maureen reservoir, although the architecture of carbonates within the Maureen was not understood. Following initial development drilling, deep-azimuthal resistivity tool inversions have been integrated with image and other log data to reveal the lithological complexity within the Maureen Formation. Future reservoir characterisation is planned to better understand the internal reservoir geometry within the Maureen drainage area, with the aim to explain production behaviour.

The drilling of Heimdal Sandstone Member development wells will be phased in during the drilling programme, and currently 45 horizontal, two multi-lateral and 22 water-injector wells are planned during field-life. The interpretation of broadband AVO seismic data as a set of geobodies has allowed the specific targeting of wells, thereby unlocking the development of the Heimdal reservoir. The Heimdal comprises a hybrid depositional sand injectite system, with injectite sands providing vertical connectivity through the gross reservoir. In areas where significant sand-injectite processes occurred, the top Lista Formation shows evidence of structural "jack-up", and candidate extrudites are identified within the overlying Dornoch Formation.

The economic development of the Heimdal faces a number of future key technical challenges, including; i) anticipating the behaviour of wells during production, specifically as the field comprises heavy-oil, ii) an absolute tie between wells and seismic geobodies is difficult, and additional sub-seismic resolution sands are identified on well-logs – so significant GRV uncertainty is carried into the development phase, iii) the degree of connectivity between Heimdal development wells (both production and water-injection) and the underlying Maureen development is uncertain. In addition, the degree to which regional aquifer pressure will support production is unknown – but both uncertainties are currently mitigated with planned water-injector wells, iv) the low recovery factor of the Heimdal, when compared to the significant in place volumes leads to the consideration of EOR methods during field-life.

While technical analysis of historic and new data has led to insights into the key uncertainties associated with the development of the Mariner Field, it is anticipated that much more will be learnt during its anticipated 40-year field life.

NOTES:

Use of Deep Directional Resistivity inversion images in development of the Kraken Field, UKCS

Peter Wood
Enquest Plc.

Deep directional resistivity (Schlumberger Geosphere tool) data has been routinely acquired in development wells in the Kraken Field. The tool allows reservoir scale imaging up to 100’ above and below the wellbore. Over 23 horizontal wellbores with a horizontal spacing of around 450 metres have been logged to date. The reservoir is Heimdal Sandstone Formation with a strong resistivity contrast and makes it an excellent candidate for use of the technology.

The data is used in two ways. Firstly, in well placement. Examples of how the data is used in real time for well placement decisions will be given. Secondly, the data has allowed a unique insight into reservoir architecture in the field. The dataset has been used to constrain reservoir modelling. Details of reservoir modelling workflows and examples of reservoir architecture in this relatively confined turbidite channel slope system will be given.

NOTES:

Skewering a Pancake: Bringing the Arundel Field Online

Rory Leslie, Zoë Sayer, Alexandra Love, Chris Hill and Rosemary Anthony
BP, 1-4 Wellheads Ave, Dyce, Aberdeen, AB21 7PB

Arundel was discovered in 2000 and comprises a thin oil column contained in high NTG, Lista, turbiditic sandstones. Despite two subsequent appraisal wells finding only thin, low net sandstone intervals at the field's crest, a tie-in point was built into the Kinnoull-Andrew pipeline over Arundel during development of the nearby Kinnoull Field. In 2015 it was decided to develop Arundel via a single producer. The well design incorporated a long horizontal section with the main sand target at the toe in order to access additional reservoir potential in the heel area.

The structure is very low relief, with depth conversion sand thickness, sand pinch out and sub-seismic faulting all identified as risks. In addition, the 25m oil column required a 15m stand-off to the oil water contact to aid water cut management, leaving only a 10m vertical window for well placement.
Pre-drill planning, effective communication and real-time collaboration were critical for successful well delivery. Modelling indicated that extra-deep azimuthal resistivity was essential for maximising pay penetration, with high resolution biostratigraphy to help land the well with precision at the top of the reservoir interval.

In May 2017, the Arundel well successfully reached TD with the extra-deep resistivity tool and biostratigraphy used to steer the 1400m long reservoir section with positive results, achieving >200m more net sand than prognosed. The well came online in September 2017, not only adding directly to production but also extending the economic life of the Andrew platform.

NOTES:

Subsurface data integration in planning for the first phase of the Lancaster field development

Clair Slightam,
Hurricane

The Lancaster Field is due to come onstream in 2019 as the first fractured basement field development on the UKCS. The nature of the fractured basement reservoir has required the integration of multidisciplinary static and dynamic datasets in order to determine reservoir properties and appropriate ranges. Whilst conventional drilling, mudlogging and petrophysical techniques have formed a key part of reservoir evaluation, new and novel forms of data acquisition/interpretation have also been applied. The impact of these novel approaches has provided a material impact on how the Lancaster basement reservoir is modelled and in the ranking of subsurface risk. Given the inherent uncertainties of undertaking a full field development of a fractured reservoir, the Lancaster field development is being approached in phases. The first phase comprises production from two horizontal wells, the long-term dynamic behaviour from which is intended to aid in reducing key reservoir uncertainties. This phased approach is anticipated to improve the ultimate field recovery through optimum well placement and appropriate scaling of facilities. The successful early development phase of the Lancaster Field will aid in the accelerated de-risking of the wider basement play West of Shetland and a route to accessing a potentially significant volume of reserves for the UKCS.

NOTES:

Maximising Economic Recovery

Simon Bibby,
Shell

Introduction

The "UKCS Maximising Recovery Review: Final Report" dated 24th February 2014 detailed the case for the creation of the Oil and Gas Authority (OGA) to 1) address the growing stewardship demands from the development of smaller, marginal fields within existing ageing infrastructure, along with 2) the strategic concept of Maximising Economic Recovery (MER-UK) and 3) the need for cross-industry collaboration. This paper considers progress to date in each of these three areas and considers where the industry is heading next.

The Oil and Gas Authority

Wood Review Recommendation 2: Create a new arm's length regulatory body charged with effective stewardship and regulation of UKCS hydrocarbon recovery, and maximizing collaboration in exploration, development and production across the industry

The OGA has been well resourced with experienced personnel to meet the vision of Sir Ian Wood. Influential, facilitating and attempting to encourage collaboration with a strong emphasis on asset stewardship, the OGA also has a focus on regional development and the creation / further development of hubs within the existing UKCS infrastructure base. This focus should not be confused with a desire to keep all existing infrastructure hubs open for business.

If the stewardship model was previously considered "light touch" in respect of intervention, where does the OGA currently sit on the scale? Field development decisions need to be taken in the UKCS, many of which have tieback and export route optionality. Is the OGA currently monitoring developments closely in the hope that field owners reach acceptable conclusions resulting in infrastructure outcomes rather than actively driving infrastructure decisions, as for example, Gassco does in Norway in its role as "system architect"? Experience so far suggests that the interventionist powers that the OGA holds will only be used as a last resort and all attempts will be made to ensure that joint venture partners reach development and export route decisions amicably. If the OGA's opinions are non-binding then sanctions can only be applied when it is clear that licence holders are acting in a way which is not in accordance with MER-UK. With over 40 years of history of acting in a way which maximises economic recovery for an oil company's own bottom line, how easy is it for the industry to now adapt and adopt a completely different way of collaborative, MER-UK thinking?

What is MER-UK?

The Central Obligation of MER-UK is that,

"relevant persons must, in the exercise of their relevant functions, take the steps necessary to secure that the maximum value of economically recoverable petroleum is recovered from the strata beneath relevant UK waters", with Supporting Obligations as follows:

- Exploration: adherence to completion of the agreed work programme,
- Development: due consideration to existing infrastructure and potential future developments in the area,
- Asset Stewardship: allowing fair and reasonable access to infrastructure,
- Technology: deployment of new and emerging technologies,
- Decommissioning: consider all viable options and decommission in the most cost-effective way,
- Plans: consultation required with OGA.

The two key behaviours underpinning MER-UK are 'Collaboration' and 'Cost Reduction'. The industry focus on cost reduction over recent years following the sharp decrease in the oil price has produced some remarkable results, ensuring the continuation and completion of field developments which were previously on hold or economically under threat of cancellation. Cost reduction performance is easily demonstrable and quantifiable, but how can progress on Collaboration be appropriately measured?

Collaboration

A reasonable, simple definition of collaboration is "an arrangement in which two or more parties work together to achieve a common goal".

The OGA's MER-UK strategy document acknowledges that compliance with the strategy "may oblige companies to allocate value between them" and that, "companies will not always be individually better off". This raises the question as to what is a satisfactory commercial return when each company has their own internal investment criteria. A challenge continuing to face the industry is therefore how to embed truly collaborative behaviours.

A new behaviour observed within the Commercial arena is an attempt to work back from the desired answer to press the case for why the maximum individual return is also a good fit with MER-UK, ("… and that's why this decision is MER-UK"). The notion of value allocation also presents an opportunity to use MER-UK as a price re-opener for legacy commercial agreements in attempt to secure a better deal. This could perhaps be justified as part of a wider package of measures in the demonstrable event of a field facing the threat of early cessation of production, but should not be considered as a carte-blanche to extract additional value from a product purchaser or service provider.

The development of a framework for and measurement of progress on collaboration was recognised as essential to facilitate the required collective culture change across the industry. The creation of the OGA's "Collaborative Behaviour Quantification Tool (CBQT)" provides a means for assessing the collaborative capability of operators, JVs and suppliers, identifying good practice and areas for improvement for cross-industry sharing of best practice to drive necessary improvements through the creation of associated actions plans. Furthermore, the recent release of the "Industry Behavioural Guidelines for Creating Quality Area Plans", developed by the industry with the support of both the OGA and Oil and Gas UK, sets out eight critical collaborative behaviours key to working with trust and transparency.

Summary

Sir Ian Wood's 2014 final report was intended to set the framework for the future of the UK oil and gas industry. The recommendations have been welcomed and positively acted upon (e.g. the creation of the OGA and the introduction of the MER-UK strategy).

The report anticipated the commercial and legal complexity of the collaboration conundrum, referring to operators who, "have pursued individual commercial objectives in isolation, with limited shared commitment or obligation to maximise economic recovery across fields or within regions of the UKCS" and, "some operators being exemplars but others apparently unwilling to accepting new tariff business at competitive rates".

The need for operators to focus on maximising economic recovery for the UK in addition to simply pursuing their individual commercial objectives is recognised and accepted, but at times has proved difficult to adopt after decades of operating in a different way. The need for far greater constructive collaboration between operators is recognised as being key to the future of the industry to enable the timely and optimal delivery of future developments.

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KEYNOTE: The UKCS opportunity and what more needs to be done to unlock potential

Glenn Brown,
OGA

There remains a significant opportunity in the UKCS to maximise economic recovery. The prize is embedded in a significant resource base both in reserves and undeveloped discoveries (contingent resources) of known hydrocarbons, much of that in field determined areas.

This talk will focus on both the remaining potential in protecting base production and what needs to be done to develop and mature UKCS contingent resources. The OGA response is to enable industry through a series of measures including fiscal attractiveness, ensuring good stewardship particularly the access to and effective use of subsurface data, and creating the right environment through licence rounds for the appropriate action to be taken.

This requires an Integrated approach across both petroleum disciplines and industry to enable an effective outcome.

NOTES:

Poster Presentation Abstracts

Estimation and Interpretation of Subsurface Pressure Regimes for Opportunity Identification and Drilling Safety in UK Sector of Central North Sea

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Many operators in the oil and gas industry consider the Central North Sea as a geologically challenging basin where operational difficulties have continued to impact on economic activities. Some of the frequently reported challenges (e.g. well control problems and breached reservoir seals) are associated with high pressures and high temperatures (HPHT) that are typical of deeply buried older and more prolific Mesozoic reservoirs that are mainly the target of many exploration and production activities in the basin. As an issue, high magnitudes of overpressure have the implication of narrowing available drilling window, often to intolerable ranges and is among the reasons for well failures, expensive well designs, complex and costly operational challenges experienced in the basin. Further to this, exploration success and well economics could be negatively impacted if high overpressure leads to the breaching of reservoir sealing rocks and consequent escape of reservoir fluids. Therefore, it is important to put the pressure regime in the right perspective so that the goal of producing hydrocarbons in a safe, cost-effective and sustainable manner in the basin will be achieved. This goes to say that strategies for maximising the economic recovery of hydrocarbons in the North Sea should ultimately lead to the reduction of the unit cost of production of oil and gas; a bulk of the bill of which is borne by the high cost of well drilling. As a way of making well construction more cost-effective, it is necessary to improve efficiency by accurately estimating and effectively planning for pressure-related challenges. Thus, this study examined the Central North Sea geopressure system based on log data and drilling information, then developed regional models of overpressure in the basin and novel algorithms for the prediction and analysis of the pressure regimes therein. From the results, there is evidence that a large proportion of the overpressures in the Mesozoic reservoirs is generated by late overpressure mechanisms especially in the inner graben areas while the shallow graben margins are dominated by disequilibrium compaction. What this means is that subject to local corrections of input parameters, overpressure can be estimated with relative ease for the Mesozoic formations in the margin areas using routine methods of pore pressure prediction. On the other hand, the deeper and hotter parts of the graben where the source rock is mature will need a combination of methods to deliver good estimates of the pressure regime and further improve the accuracy of other interpretations (e.g. seal integrity) that are significantly functions of overpressure variations in the system.

Azimuthal anisotropy at a fluid escape structure in the northern North Sea

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Shallow and young sediments contain up to 90% porosity filled by sea water. During burial the porosity decreases and the pore and/or bound water migrates along low-permeability zones to escape through high permeability vertical fracture networks created by hydro-fracturing, such as chimney and pipe structures. However, the physical properties such as the permeability of these chimney / pipe structures with respect to their surroundings, and their longevity, remain poorly known. Aligned fractures are known to produce seismic anisotropy. Seismic anisotropy therefore offers a way of exploring the density and orientations of cracks, which are linked to the stress history and the physical properties of a region.

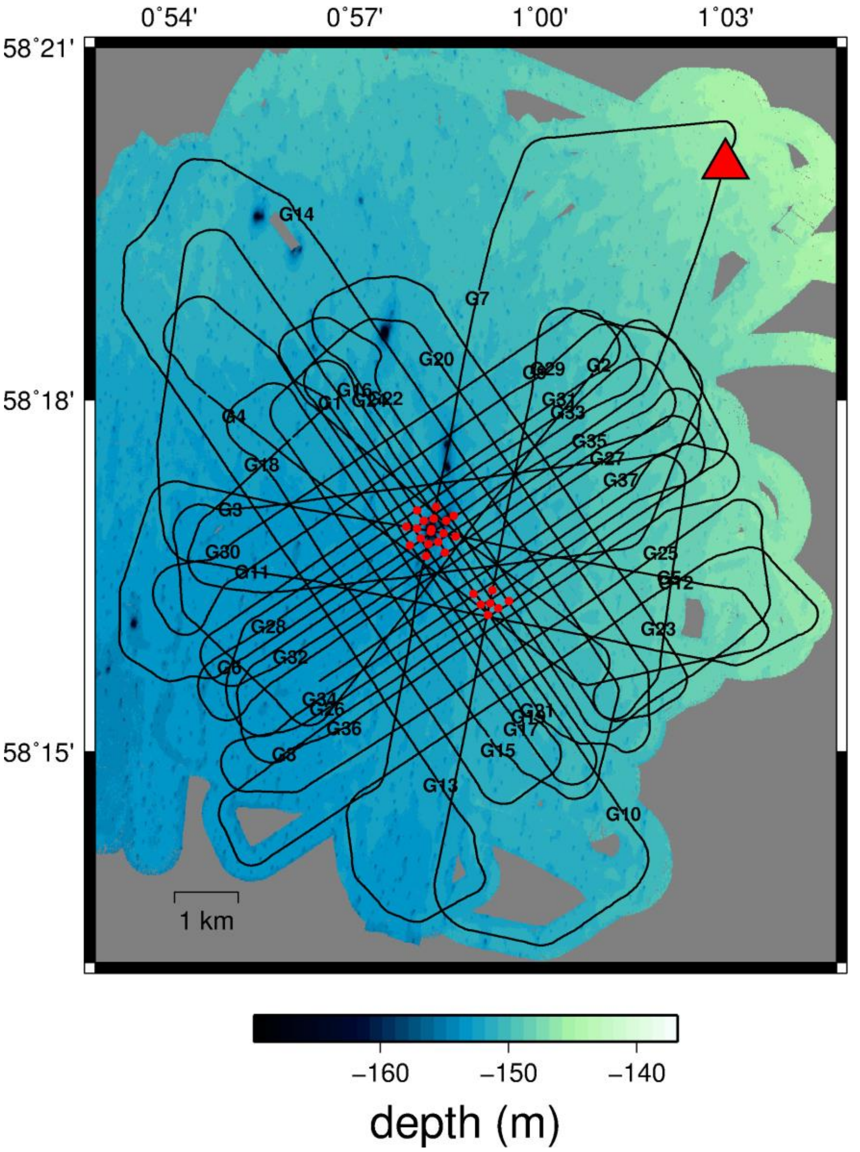

Figure 1: Map of the GI gun survey. Red dots represent the ocean bottom seismometers and the red triangle is the lander device equipped with a hydrophone that allows high sapling rate recording.

In September 2017, to learn more about the structure and physical properties of gas-bearing sediments and the vertical fluid flow conduits associated with them, we carried out the NERC-funded CHIMNEY broad band seismic experiment (James Cook 152) around the Scanner pockmark in the northern North Sea. The Scanner pockmark is an active gas seepage zone located on top of a circular, diffuse seismic anomaly with bright zones indicating the presence of gas. We deployed 25 ocean bottom seismometers (OBS) within and around the Scanner pockmark. These instruments recorded shots from five different sources (Bolt airguns, GI-guns, two different surface sparkers and a deep-towed sparker source) offering a wide range of frequencies, along a survey designed to achieve multi-azimuth shot coverage.

The azimuthal anisotropy within the Scanner pockmark and the surrounding North Sea sediments will be first explored using the particle motions of PS converted (C-) waves from the GI gun-source recorded on the OBS network. The multi-frequency dataset recorded with a high sampling rate (4 kHz) allows the clear identification of wide-angle seismic reflection phases and therefore can also be used to constrain the degree and the direction of the anisotropy, as well as topographic variations of the interfaces in and around the pockmark. OBSs have also recorded wide-angle refraction phases from both, Bolt airgun and GI-gun sources, which will also help approaching the anisotropic parameters of the medium, as well as the seismic wave velocities. We expect to observe variations between anisotropic properties of the layered sediments of North Sea and the Scanner pockmark affected by vertical conduits for fluid flow.

Quantative Characterization of Ichnology Based on Core photos and CT scan

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Quantitative characterization of bioturbation or trace fossils is of great importance in geosciences. Several methods proposed since the 1960s are mainly based on visual or subjective observation. The first semi-quantitative evaluations of the Bioturbation Index, Ichnofabric Index, or the amount of bioturbation were attempted, which used a series of flashcards designed in different situations]. Recently, more effective methods involve the use of analytical and computational methods such as Seizes Diversity Index, X-rays, magnetic resonance imaging, or Computed Tomography. These methods, although complex, provide results with better clarity and resolution.

This paper presents a combined method which aims to characterize the bioturbation quantitatively by high resolution core photos and CT scan images. The core photos were manipulated in Adobe® Photoshop® software CS6 to identify 2-D ichnology types, size, and diversity. The CT scan images were handled in Avizo® to estimate the spatial scales and assemblages of trace fossils. This method shows great superiority than previous studies which mainly based on core or subjective estimation.

We adopted this method to MacKay Ⅲ, an oil sands lease in Alberta, Canada. The ichnological features of the target layer, McMurray Formation, Lower Cretaceous, were analyzed. Five types and three associations of trace fossils were identified and then interpreted. Five kinds of trace fossils include *Palaeophycus, Planolites, Rosselia, Skolithos, Teichichnus;* three dominated associations are *Palaeophycus-Planolites, Planolites-Skolithos, Skolithos-Teichichnus.* The Bioturbation Index, which varies from 0-6, and the spatial scale of these trace fossils were also evaluated. This study can provide not only a basis for further geological evaluation, but also a reliable reference for nearby areas.

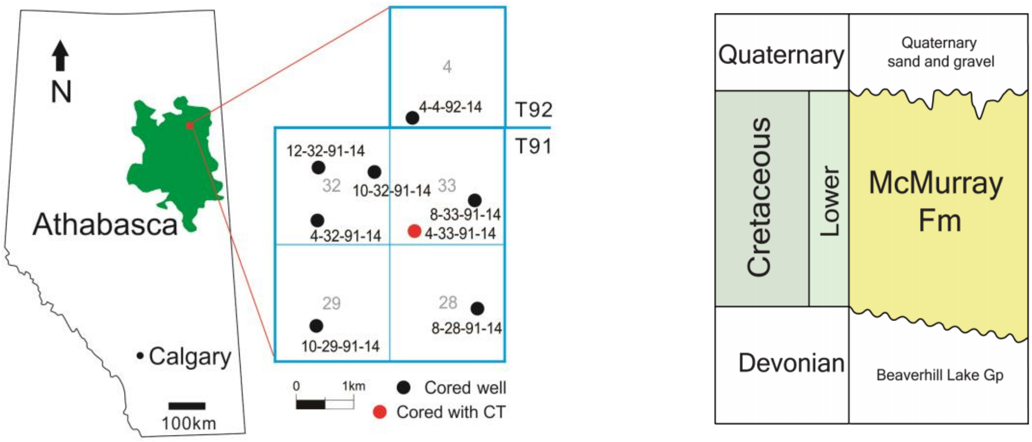


Fig 1. The location of MacKayⅢ oil sands and strata column

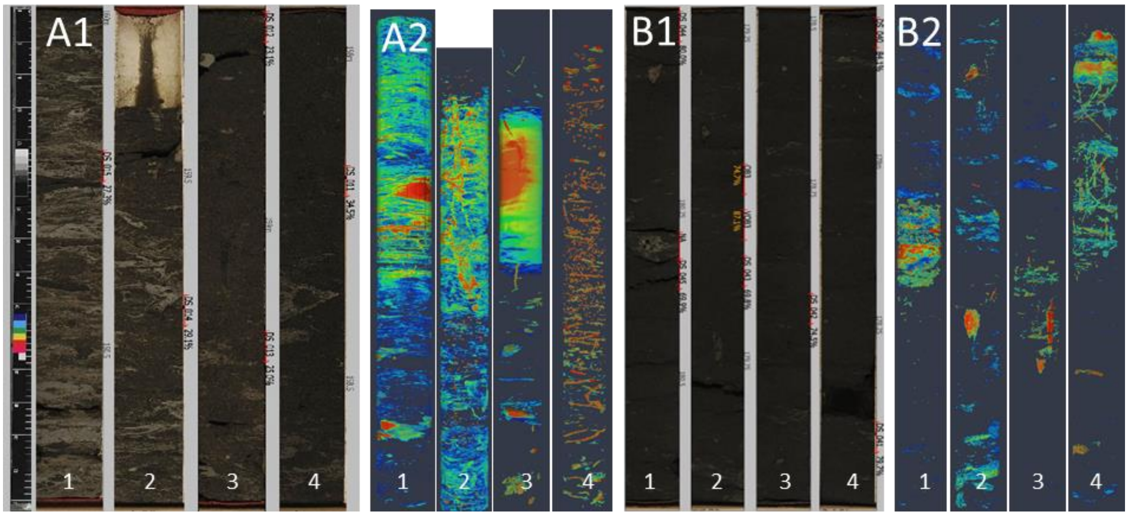
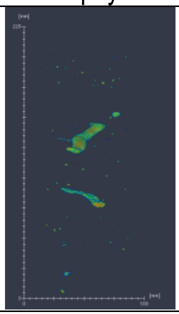
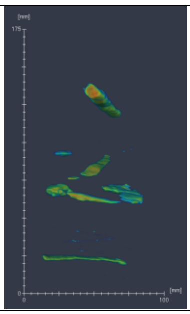
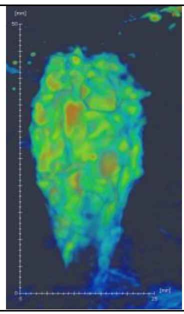
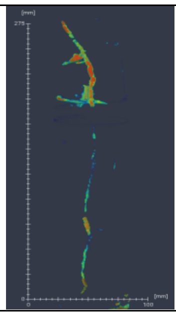
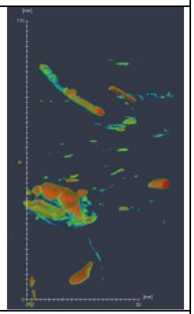


Fig 2. The core photos and CT scan images of McMurray Formation, Mackay Ⅲ

(A1, A2: 4-33-91-14 well, 157.94-160.72 m; B1, B2: 4-33-91-14 well, 176.31-180.80 m)

Table 1 The Ichnological features of McMurray Formation, Mackay Ⅲ

Name		Palaeophycus	Planolites	Rosselia	Skolithos	Teichichnus
CT Images						
Depth(m)		162.40-162.50	163.25-163.40	180.10-180.20	165.46-165.66	176.50-176.60
CT value		1700-5000	1400-4800	1100-1800	3000-5000	1800-2500
SS*	No.	14	33	3	42	8
	L*	53.75	58.15	45.67	64.48	47.61
	W*	8.32	6.34	24.26	1.52	9.79
	H*	4.52	3.75	12.32	1.24	4.64

*SS: spatial scale; L: length (mm); W: width (mm); H: height (mm)

Impact of impurities on the rheological behaviour of salt rock

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There are various forms of natural and man-made underground features (e.g. depleted reservoirs, aquifers, salt caverns) that can be used to store gas and fluids for industrial, commercial or energy supply purposes. Salt cavern storage sites are man-made holes created by drilling a well in a salt rock formation and using water to wash out salt by dissolution. Salt rock is considered a good geological lithology for the construction of storage sites due to its physical properties. Salt has a very tight fabric, resulting in a very low permeability, which makes it a favourable sealing material to host fluids. Underground geological storage of methane (CH4) and hydrogen (H2) gas is an efficient way to meet energy demand fluctuations, when the electricity grid supply does not match the demand, providing high withdrawal and injection rates depending on their working gas capacity. Stored gas in salt caverns can be used for power generation or fuel for heating in peak demand periods in order to ensure supply, particularly during colder days or when energy suppliers experience technical difficulties. Moreover, recently the option of storing hydrogen to provide low-carbon power generation to the UK's electricity grid has been investigated, combining hydrogen storage in salt caverns with gas turbines.

Geologically, salt formations are predominantly formed of halite, but they can also contain impurities and other evaporite materials such as anhydrite, gypsum, clay and other minerals or mud .The presence of impurities can affect the rheological properties and deformation mechanisms of salt rock. The rock deformation can change the size of salt caverns; for example, salt flow by dislocation creep which may shorten the useful life of a cavern. By understanding these factors, engineers can achieve better design and execution of projects as a function of the rock composition and environmental conditions. This research project focuses on the impact of impurities on the rheological behaviour of salt rocks. Synthetic salt rock samples with different types of impurities are being manufactured in order to have better control on the influence of the type of impurities, their composition and quantity. This level of control will allow clear links to be established between sample characteristics and deformation behaviour. In addition to the synthetic samples, natural samples (e.g. Permian and Triassic salt rocks from different salt mines in the UK and Poland), are being subjected to cyclic and thermo-mechanical loading tests. The rock samples are microscopically analysed before and after mechanical tests, and predictive rules are being developed to predict the impact of type and distribution of impurities on the rheological behaviour of the salt rocks.

Robert Gordon University, Aberdeen

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