Tertiary Fan Reservoirs of the North Sea

31 August – 2 September 2011

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Thursday 1st September

Keynote Speaker: Maximising Recovery from North Sea Tertiary Fan Reservoirs

Susan Currie, Malcolm Pye, *Department of Energy and Climate Change*

Approximately 4000 exploration and appraisal wells have been drilled in the North Sea. A further 6000 wells have been drilled to develop and produce hydrocarbons from almost 400 fields.

Fields in the North Sea which have Tertiary age submarine fan reservoirs include, amongst others, Forties, Montrose, Pierce, Mungo and Bittern in the UK sector and Balder, Alvheim, Frigg, and Heimdal in the Norwegian sector. These submarine fan system reservoirs have given rise to some of the largest oilfields in the province, with hydrocarbons initially in place in the Forties Field over 4500 million barrels, and a large number of more modest accumulations.

There is a large body of information about these reservoirs gained from analogue outcrop studies, remote sensing, drilling, and a development and production history stretching back forty years. Tertiary fans provide some of the best quality reservoirs in the North Sea with average porosities often >0.25 and permeability >1.0 Darcy. Over the last thirty five years the reservoirs have been produced with varying degrees of success using a range of techniques including vertical, inclined, and horizontal wells, water-flood, and natural depletion schemes. Depending on reservoir quality, the degree of channelling and faulting, and the development plan, recoveries greater than 60% have been achieved although the average recovery factor is around 40%. Many individual wells in these reservoirs have produced in excess of 10 million stock tank barrels of oil.

This presentation will look briefly at recovery factors in some of the better known submarine fan reservoirs and will review some of the less well known fields highlighting the different ways they have been developed, the field performance, and their actual and estimated recoveries. The similarities and differences between fields with higher and lower estimated recoveries will be examined.

By providing an overview of the province we hope to ‘set the scene’ and emphasise the richness of the data source associated with North Sea submarine fan reservoirs as well as the potential for increasing recovery.

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Regional Controls on Tertiary Fan Deposition in the North Sea and Northeast Atlantic Margin Basins

David Mudge, *David Mudge Consulting*

Fan sandstones of Palaeocene and Eocene age are widely distributed in the North Sea, West of Shetland and Møre basins. Early Tertiary deposition in these basins was affected by extension and thermal uplift leading to continental breakup and the start of sea-floor spreading between Greenland and Europe in the early Eocene. Active rifting overprinted by episodes of thermal uplift, accompanied by volcanism and extensive sill intrusion, took place in the West of Shetland area which was located closest to the line of breakup. In the more distant North Sea, extension led to reactivation of old Mesozoic faults whilst volcanic activity was limited to the deposition of tuffs. At the same time, uplift of the Scotland-Shetland landmass produced a high-relief source area that contributed large volumes of clastic material to both the Faroe-Shetland and North Sea basins. Much of this sediment was deposited as slope or basin sands in channel and fan systems. Palaeocene sandstones drilled in the Møre Basin were derived from the Norwegian margin to the east, whilst westerly sourcing of sands from the Faroe Platform and Møre Marginal High remains uncertain.

The regional uplift surfaces, flooding surfaces and igneous rocks that formed during the Palaeocene and Eocene are preserved in the well record. Analysis of a large number of wells has established a detailed sequence stratigraphy for this interval, using the unconformities and high-gamma mudstones as sequence boundaries. Many of these surfaces form regional seismic reflectors. The stratigraphic position of the high-gamma mudstones, which represent condensed deposits associated with marine transgressive maxima, is tightly constrained by biostratigraphic data. The unconformities are also well defined biostratigraphically, with missing section and major microfossil assemblage changes and extinctions occurring across many of these surfaces.

Dating and correlation of these regional surfaces is important in hydrocarbon exploration because of their intimate association with reservoir sandstones, with the base of each sandstone package being marked by unconformity and the top by a high-gamma mudstone. Using this stratigraphic control, sand distribution and depositional environment maps have been produced for nine Palaeocene-Eocene plays in the North Sea and northeast Atlantic margin basins. These tell a fascinating story of episodic uplift events, associated with sand influx into the basins, interrupting a succession of longer term transgressive-regressive cycles represented by mud deposition. Sand accumulations reached their maximum areal extent during the late Palaeocene (Thanetian) regression, with development of the coeval North Sea Balmoral/Heimdal and West of Shetland Lamba fan systems. Eocene fans, deposited during a dominantly transgressive phase following continental breakup and the cessation of thermal uplift and extension, are much smaller and less widespread.

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The Sedimentology and Evolution of the Paleocene Sele Formation Sandstones Central North Sea, UKCS

Chris Davis, Ben Kilhams, James Eldrett, *Shell UK*

Since the first discovery of Paleocene hydrocarbon reservoirs in the late 1960's the turbiditic cycles of the Central North Sea have become one of the most economically important stratigraphic intervals in Northwest Europe. Of the many turbidite fans found within the North Sea the deep-water deposits of the Forties Sandstone Member, that form a 300 km long, mixed sand-mud basin fan, are some of the better known and has become one of the most prolific intervals for producing hydrocarbons from within the Paleogene.

At first pass reservoir quality prediction within the Sele Formation sandstones could be based upon a 'classic' deep-water basin floor fan model where changes in relative sea-level ultimately control the advancement of sandstone along the main depositional fairways. In this model debrites (the deposits of a debris flow) are constrained to the slope break while coarser grain-sized, higher net-to-gross, better quality poro-perm sandstones would be expected to be encountered in the more proximal parts and along the axis of the fan system.

This basin floor fan model is complicated by the underlying graben structure and halokinesis within the Central North Sea that results in modified seafloor bathymetry that can affect the behaviour of sediment gravity flows across the basin. A number of cross cutting lateral fans have been identified along the length of the western margin of the Central Graben (i.e. Gannet Fans) which represent a secondary source of clastic material that overprint the expected down fan changes in grain-size and net-to-gross. Another complexity is the mixed sand-mud nature of the fan system that can produce sediment gravity flows enriched with mud that can modify the fluid resulting in the formation of hybrid sediment gravity flows (a single gravity flow that has components that behave under both turbulent and laminar flow regimes). The deposits of these hybrid flows (a single event bed composed of both turbidite sandstone and a co-genetic or 'linked' debrite) along with remobilised sediment off the flank of active salt highs can result in complex stratified reservoir architectures and sudden and unexpected reductions in reservoir quality.

This presentation aim to show work carried out by the Shell group along with work from Shell sponsored University projects that show Shells current understanding of the Forties Fan System.

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The Forties Field after 36 Years Production: A Mature Asset with Abundant Bypassed Pay Targets.

Phil Rose, *Apache*

The Forties Field, discovered by BP in 1970 with first production in 1975, has been a remarkable asset over its 36 year production life. It was the largest UK oil producer during its early life and today only the Buzzard Field produces more oil on the UKCS. The current productivity of the field is the result of Apache's ongoing drilling and facilities refurbishment campaign.

In the eight years since Apache purchased the Forties Field from BP over 100 infield targets have been drilled with an overall success rate of 74%. As a result the field production rate has been held at a plateau rate around 60,000 bopd despite 42,000 bopd average production in 2003, the year of purchase. Key to Apache's success on Forties has been a constant drive to push the boundaries of 4D seismic interpretation and lithology prediction from seismic and the ability to integrate this information with local production and well data.

In this paper the trapping style of bypassed targets will be described. The role of the complex Forties depositional architecture together with subtle compactional faulting in generating these traps will be discussed. The distribution of bypassed pay traps will also be considered in terms of the evolving history of Forties production and water injection locations. The Forties case study is an interesting example of a field where simulation would not have been a sufficient tool to predict the location of some of the best bypassed pay locations in the field. This is due to the very subtle seismic expression of many of the features ultimately responsible for holding back oil.

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Arran Field: A Complex Heterolithic and Marginal Field Development

Steve Kenyon-Roberts[1], Jamie Collins [1], Natalie Bordas-Le Floch [1], Brian Cullen [2], Jason White [1], John Downey [1]

[1]*Dana Petroleum*
[2]*Reservoir Associates North Sea*

The Arran field contains gas-condensate reservoired within the Palaeocene Forties Sandstone Member of the Sele Formation. It is located along the lateral margins of the medial Forties turbidite depositional system, on the flank of the Central Graben's Eastern Trough.

As part of the field development planning process, a comprehensive re-evaluation of subsurface data was undertaken. A major hurdle in the project was developing a detailed understanding of the reservoir distribution in an extremely heterolithic marginal depositional environment. A thorough understanding of the reservoir distribution and turbidite architectures was key to ensuring that the appropriate elements were captured within the reservoir model. This was achieved through detailed integration of data interpretations from across the discipline spectrum, including detailed seismic, core and analogue data.

Core data show that the Forties reservoir in Arran consists of stacked amalgamated and non-amalgamated fairway sandstone bodies. These reservoir units are extensively interbedded with heterolithic low density turbidite fringe deposits, slumps, and debris flows, along with hemipelagic and turbiditic shales. The core observations, in terms of the facies present, stacking patterns and facies architecture, coupled with the medial location of the Arran field within the Forties turbidite system, suggest the reservoir consists of broadly tabular elongated turbidite lobe bodies, deposited predominantly from high density turbidites. Outcrop analogue data from Gres d'Annot, SW France, further supports deposition of elongated turbidite lobe bodies. A seismic Vshale attribute volume, derived from inverted Pre-SDM data, together with reflection seismic data were used to identify and map reservoir geometries. The data shows elongated lobe bodies derived from the northwest, as well as large scale lobes onlapping onto the Jaeren High that migrated laterally over time. Suspected slump units were also identified, predominantly derived from the edges of the Arran North salt diapir, suggesting the basin floor topography was evolving during deposition.

The seismic Vshale volume was used as a soft linkage to condition the facies model. This was achieved through use of facies probability data, driven by the seismic attribute correlation with well facies data. Core and analogue data were utilised to ensure appropriate reservoir body geometries and spatial relationships were maintained. This integrated approach also allowed for various uncertainties to be captured, with specific focus on vertical and lateral reservoir connectivity.

The multidisciplinary approach adopted for this project ensured that a detailed understanding of the Forties reservoir architecture was developed and then captured within the static and subsequent reservoir models.

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Reservoir Geology of the Palaeocene Forties Sandstone Member in the Fram Discovery, UK Central North Sea - Managing Uncertainties in a Distal Sheet-Like Turbidite Reservoir

David Jones, Samantha Large, Alan McQueen, Ahmed Helmi, Mariano Floricich' *Shell U.K. Limited*

The Fram discovery, located in Blocks 29/3c, 29/8a, 29/4c and 29/9c in the UK Central North Sea, comprises Palaeocene age Forties sandstones with an oil rim and primary gas-cap trapped within a 4-way dip closure around a pierced salt diapir.

The Forties Sandstone Member reservoir at Fram is characterised by very fine to fine grained sandstones interbedded with shales with minor slumping and sand injection features interpreted as the product of high-density turbidity currents and high energy sandy debris flows with deposition in an overall distal and marginal basin-floor lobe environment.

The layered reservoir architecture of the Forties is considered to be the result of a series of compensationally stacked lobes characterised by a systematic variation from an axial amalgamated facies to thinner bedded heterolithic sands. The reservoir thickness and quality of the Forties at Fram is thinner and poorer when compared to more proximal Forties fields however the sheet-like reservoir architecture of the reservoir results in good lateral continuity and connectivity when compared to more channelised Forties reservoirs.

Following discovery of Fram well 29/3-1, drilled by Shell and Esso in 1969, the field was not appraised until 1999 when the 29/3a-6 appraisal well was drilled. Although, the 29/3a-6 well proved the presence of good quality reservoir down-dip of the 29/3-1 discovery well, and was successfully production tested at a rate of 18.6 MMscf/d of gas and 1473 bpd condensate, it failed to establish the fluid contacts for the field instead encountering a gas-down-to.

Despite the encouraging results from the 29/3a-6 appraisal well due to the nature of the Forties reservoir significant uncertainty remained regarding reservoir thickness and quality, hydrocarbon saturations and the depth of the fluid contacts, resulting in a wide range of both in-place and recoverable volume estimates. In addition evidence from 3D seismic AVO/inversion datasets and nearby exploration wells indicated that an earlier oil charge of the structure was likely and suggested that an oil rim may be preserved below the gas-cap.

As such it was decided that prior to field development further appraisal of the reservoir was required and the 29/3c-8,8z appraisal wells were planned and drilled in early 2009. The appraisal drilling campaign included LWD/wireline logging, NMR logging, MDT pressures and fluid sampling and OBMI borehole image logs. In addition a 122ft core was acquired from the Forties reservoir interval for petrophysical evaluation including SCAL and the 29/3c-8z well, which encountered the oil rim, was successfully DST production tested.

This presentation aims to provide an overview of the Fram Forties reservoir geology and sedimentology and show how the integration of datasets collected in the 29/3c-8,8z appraisal wells with the 3D seismic data, existing E&A wells and producing analogues has helped reduce the key subsurface uncertainties required to be addressed during the field development planning phase.

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Mungo: A Phased Development of a Palaeocene Salt Diapir Field.

Mary Ward, Mark Williams, Richard Pollard, Liz Padmos, *BP Exploration and Operating Company*

The Mungo field in the Central North Sea Eastern Trough, 143 miles east of Aberdeen, comprises Palaeocene sandstone and chalk reservoirs draped over a steeply dipping salt diapir, sealed beneath Eocene mudstones. Primary production is from the Palaeocene sandstones. Mungo has been developed in a phased manner from 1998 onwards with an initial development of nine producers, two water injectors and one crestal gas injector. Through time, Mungo performance has shown strong compartmentalisation with some areas pressure maintained by waterflood and other areas on pressure depletion. A consequence of compartmentalisation was that well configuration was suboptimal so subsequent phases of infill drilling were included in the long term plan.

A full model rebuild was deemed necessary as the basis for further drilling. The main challenges were how to capture the large range of uncertainty in reservoir description and the impact of compartmentalisation. Following a work programme of compartment screening, sector modelling, and testing of multiple reservoir scenarios to investigate reservoir uncertainty, a three well infill well programme was sanctioned and the wells were completed in 2009.

To improve definition and reduce the risk of remaining infill targets on Mungo, HDOBC seismic was acquired on the eastern flank in 2010 and is currently being acquired on the western side of the field. In parallel, a regional study of the Palaeocene fan in the Central North Sea was carried out along with a core study to review and refine the depositional elements and the interpretation of GDEs and RDEs in support of model building activities to identify additional infill targets for further development of the field.
This presentation will provide a case study of Mungo development and will summarise how subsurface uncertainties have been dealt with and will discuss the future vision for reservoir development.

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Pierce – Using Reservoir Behaviour to Constrain a Geological Model of a Complex Turbidite Field.

Ewan Robertson, *Shell UK*

The Pierce field is located at the eastern margin of the UK sector Central North Sea. It lies on the western flank of the Jaeren High against which the Forties system thins and shales out. It comprises two saturated oil accumulations, North & South Pierce, each associated with a salt diaper. The main reservoir unit, the Forties sandstone member, has been biostrigraphically constrained to the Upper Palaeocene and within the overall Forties submarine fan system, Pierce can be described as medial to distal.

Locally the Forties sandstone was deposited across an undulose topography created partly by movement of salt and partly by Lista/Marueeen shales. This topography served as a container in which sediments were constrained (T70 biostrat zone). However, once depressions were backfilled, subsequent mass flows changed character from channel to unconstrained sheet like deposits (T75 biostrat zone). Further relative movement of the diapirs shifted the axis of deposition slightly westward and eastward leaving lower quality, finer grained sand closer to the salt.

On the eastern and western margins of the south diapir, and on the north flank of the north diapir, relative movement of salt also created slumping. In south Pierce, the eastern slump occurred relatively early, creating a barrier to subsequent mass flows. Tracers in injected water have been observed in producers outwith this slump area, leading to a hypothesis that limited bypassing has occurred. Characterisation of the eastern slump as an isolated, thin, poor quality wedge has derived from dynamic pressure data, contact data and the available seismic.

In contrast, the western slump occurred much later as significant movement of hydrocarbons and injected water are observed between wells out of the slump area. Changes in OWC are observed across the mapped extent of the slump area indicating these slump style faults have some control over dynamic behaviour of the field.

Significant backfilling and ponded sediments in the saddle area have arisen from a combination of being in the main sediment fairway and the late slumping on the western flank. Thicknesses of Forties sands here can exceed 1000ft. The early slumping on the eastern flank created ponded sediments on a large scale in and around the immediate area also. Poor well results from a saddle infill well have highlighted the requirement for understating complex depositional patterns in the saddle area.

An integrated approach by use of seismic, 4D seismic, pressure, tracer and geochemistry has been used to build and refine a conceptual model of this complex reservoir. Observations of dynamic behaviours have been interpreted and fed back to the Geological model to improve overall understating. Based on these data, infill targets have been identified and drilled to stem the decline of the Pierce field.

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Bittern Further Developed Through Integration

Suzanne Coogan, Mensur Hodzic, Jon Brain, Susie Bradford, Saad Khan, Samantha McClean, Lara Okubanjo, **Lucy Ritchie** and Derek Cowie, *Shell*

The Bittern field is located in the West Central Graben of the North Sea, 190 km ESE of Aberdeen. The field was discovered in 1996 and developed during 1999/2000 as a subsea tie-back to the Triton FPSO, 23 km to the north. The Bittern reservoir consists of approximately 200-300 ft of Eocene age turbidite sandstone with minor heterolithics and shales. Reservoir quality is excellent with a net-to-gross of about 0.95, porosities of 0.32 and Darcy quality permeability. The field comprises a simple 4-way dip closure with a 100 ft primary gas cap and 160 ft oil column.

The Bittern Sandstone Member forms a northwest-southeast trending fairway which is typically 4-5 km wide. The architecture of the fairway is interpreted to reflect topographically controlled sedimentation of the Bittern sands between subtle topographic highs defined by previously deposited Forties sandstones.

The reservoir is sub-divided into three sands (Upper Bittern, Lower Bittern and Lowermost Bittern) by two biostratigraphically constrained heterolithic layers known as the Ochre and Orange markers. Within the Upper Bittern, 2-3 ft thick intra-reservoir heteroliths are correlatable over large parts of the field. Understanding the sedimentology and depositional extent of these heteroliths is of key importance as they have been identified as conduits for water over-ride in certain parts of the field.

Initially, the field was produced with four production wells and two water injection wells. An additional production well was drilled on the crest of the structure in 2006, but experienced water breakthrough and was shut in. Logs showed water override on the intra-reservoir shales, high on structure and the decision was taken to halt further development until the dynamic behaviour of the reservoir was understood.

A surveillance plan consisting of 4D acquisition and production logging was executed in 2008. Subsequent integration of the data resulted in the identification of several infill opportunities with significant potential remaining volumes. An optimized static/dynamic workflow enabled rapid turnaround of different subsurface realizations and enabled an understanding of the fluid distribution in the reservoir, specifically water override zones. This, facilitated by close communication and integration with the well engineering team, enabled an optimal completion strategy to be defined to maximize oil production, whilst isolating gas and water override zones.

In 2010, the Integrated Bittern Team delivered two, on prognosis subsea wells within an accelerated timeframe. Well execution was successful and resulted in validation of the subsurface model.

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Gannet A: A Thin Oil Rim Development in a Dynamic System

Gwilym Lynn, Morgan Bacciotti, *Shell UK Ltd*

The Gannet A field is an Eocene aged Tay Sandstone Member reservoir located in the Central North Sea. The reservoir comprises a turbidite fan complex deposited in a deep water setting sourced from the uplifted Scottish Highlands. The field was discovered in 1972, with development commencing in the early nineties (first oil in 1993) with a small platform centred over the Gannet A field in conjunction with a number of subsea satellite fields. These fields develop a range of deep water deposits of Palaeocene and Eocene age.

The Gannet A field has a thin oil rim (50 ft) and overlying gas cap (60ft). The Tay Sandstone Member in Gannet A is on average 200ft thick and is composed of very high quality reservoir sands. Net-to-Gross is around 90%, with porosities of around 30 p.u. and permeabilities in the order of 1.5 Darcies. The structure is dip closed, with a stratigraphic pinchout to the west against the Gannet B and Gannet C salt diapirs.

The field is located on the southern side of the main Tay fairway and deposition has been strongly influenced by pre-existing basin architecture at the time of deposition. The depositional architecture has strongly influenced the reservoir behaviour with shale positioning and geometries interpreted to be controlling production, water-cut development and fluid distributions throughout the field. The field is connected to a large and active aquifer, which combined with the high reservoir quality, has led to a highly dynamic system during production, with significant migration of fluids around the field observed as offtake evolved.

The field was originally developed through a combination of 11 long horizontal wells targeting the oil rim and 2 vertical gas injectors to maintain the gas cap through gas reinjection. During production, the strong regional aquifer induced the migration of the oil rim to the crest of the reservoir in the north and east of the field, with the remaining gas cap now located in the south west of the field. As production has progressed, the integration of surveillance data and 4D time lapse seismic has allowed the contacts in the field to be monitored. This data has led to follow-up development activities aiming at targeting the migrating oil though upward recompletions and sidetracks of existing wells.

Recent work has concentrated on attempting to better understand the controls on this highly dynamic field. Static and dynamic models have been built integrating the full range of data available in order to achieve a successful history match. These models have achieved a spatial match to the 4D data and matched the information on contact movement with the surveillance data gathered in the wells.

Data gathering and integration acquired during the development of the Gannet A field has allowed a better interpretation of the reservoir geology, which has in turn been used to improve our overall understanding and hence production from this Central North Sea field.

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Geophysical, Petrophysical and Sedimentological Characterisation of the Paleocene Lista and Maureen Formations, UK Central Graben

Ben Kilhams[1], Adrian Hartley[1], Mads Huuse[2], John Marshall[3]

[1]*Geology and Petroleum Geology, University of Aberdeen, Aberdeen, United Kingdom.*
[2]*School of Earth, Atmospheric and Environmental Sciences, University of Manchester, Manchester, United Kingdom.*
[3]*Shell UI Europe, Aberdeen, United Kingdom.*

Thanks to the regional prospectivity of the Paleocene interval there is an extensive associated dataset of 3D seismic, well logs and core material. The provision of these datasets by Shell UI Europe has enabled a regional-scale re-evaluation of these deposits. Observations from seismic, core and well log analysis are used to map the reservoir quality and seismic stratigraphy of the Paleocene Maureen and Andrew sandstone members and advance our understanding of the syn- and post-depositional dynamics within the submarine fans.

The use of regional seismic data allows observations to be made about the extent, thickness, net to gross, bathymetric interaction and temporal evolution of the submarine fans. Observations from seismic data benefit greatly from correlation with core analysis and an extensive well database. Core from 28 wells has been studied to evaluate the types of facies present and how these relate to bed connectivity, grain size distribution and porosity/permeability trends. Furthermore, integration of a regional well database (containing 338 wells) allows for large-scale mapping of formation thicknesses and reservoir quality. In turn, this has enabled seismically derived maps to be ground-truthed enabling a more quantitative approach to seismic attribute-based reservoir mapping.

The integration of these observations enables powerful interpretations to be made with both academic and industrial applications. Examples are presented showing potential scientific advances including clarification of our understanding regarding the spatial and temporal evolution of the submarine fans from source to sink. Observations are made concerning the impact of basin geometry and salt-induced bathymetric variations on reservoir property distribution as well as potential changes in the source area and the validity of previous models. Maps of sediment distribution and reservoir quality allow industry workers to consider the remaining prospectivity within these intervals. It is hoped that this study will prove valuable to workers in both the Central North Sea and global deep water sedimentology.

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Friday 2nd September

A Decade of West of Shetland Seismic – Improving our Reservoir Understanding

Sue Fowler, Chris Hill, Peter Allan, Steve Campbell, *BP Exploration and Operating Company*

The BP-operated Foinaven and Schiehallion oil fields lie around 150km west of the Shetland Islands in water depths of 350 to 500m. Complex Lower Tertiary sequences of deep marine turbidite sandstones provide the reservoir intervals. Both fields are further compartmentalised by a series of W-E trending normal faults.

Both 3D and 4D seismic have been a vital element in the development of both fields. Seven joint 4D seismic surveys have been acquired at regular intervals since production started in 1997 for Foinaven and in 1998 for Schiehallion with the most recent survey being acquired in 2010.

Continual improvements in seismic acquisition and processing techniques have resulted in significant enhancement of the 3D and 4D seismic images over time. Recent improvements have been sufficiently great to justify reprocessing earlier surveys to bring these up to the standard of the latest datasets. This has provided high quality suites of 4D seismic surveillance images spanning over 10 years of production history.

These improved images have had a significant impact on the mapping of the reservoir sands and understanding of their connectivity and the subsequent fluid movements and pressure changes in the reservoirs. Contributing to improved history-matched reservoir models and the identification and optimisation of reservoir management and field development opportunities.

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Palaeocene Depositional Systems in the Norwegian North Sea: Controls on Sand Distribution and Architecture

Evelina Dmitrieva[1], Christopher Jackson[1], Mads Huuse[2], Adam McCarthy[3]

[1]*Department of Earth Science and Engineering, Imperial College, London, UK*
[2]*School of Earth, Atmospheric and Environmental Sciences, University of Manchester, UK*

The majority of reservoir sandstone units in the Palaeocene and Eocene in the North Sea originated as deep-water channel and fan deposits. Previous work has mainly focused on the development of these systems along the western margin of the basin, where a number of large hydrocarbon fields producing from Palaeocene and Eocene reservoirs are present. To complement these studies, this study focuses on the Palaeocene to Lower Eocene succession within the Norwegian sector along the underexplored eastern margin of the basin. In this region, sands sourced from the Norwegian mainland were transported towards the central parts of the North Sea Basin by a variety of debris-flow and turbidity current processes. The aims of this study are; (i) to establish a stratigraphic framework for Palaeocene-to-Eocene deepwater sandbodies along the eastern basin margin of this basin; (ii) to establish the original depositional morphology of these sandbodies prior to large-scale, post-depositional remobilisation and injection; and (iii) to investigate the controls on the overall architecture and distribution of these deepwater deposits. The study utilises 3D seismic surveys which cover ca. 3600 km² offshore Norway. 48 exploration wells with wireline and cuttings data are also utilised, core data for the study interval is very sparse.

Well data indicate that the studied interval consists mainly of sandstones interbedded with claystones and siltstones. The sandstones are fine to coarse-grained and poorly to well-sorted. Individual sandbodies, up to 90 m thick, occur at different stratigraphic levels. Well and seismic observations suggest that the sandbodies are of limited lateral extent due to deposition in a channelized setting. As a result, individual sandbodies cannot be confidently correlated between wells. In addition, examples of compensational stacking of sandbodies are observed. Well-seismic ties indicate that the thicker sandbodies are often represented by high amplitude anomalies. Anomalies with both channel and sheet-like geometries are observed, with channels reaching up to 10 km in length and up to 2 km in width. Mounded depositional features, up to 2.5 km wide, are also observed. The distribution of these features matches the well-based observations of sand occurrence, indicating that sands are best developed towards the basal (Palaeocene) part of the succession. This distribution is consistent with regional palaeogeographic reconstructions which suggest that sediment input from the E was most voluminous during the Early Palaeocene, and declined through time into the Eocene. Furthermore, seismic observations suggest that the topographic relief of the base Palaeocene, as well as the routing of Palaeocene sediments is structurally controlled.

Chrono- and lithostratigraphic key surfaces are identified in well data and six main stratigraphic units are suggested for the study interval. Four of the identified units are within the Palaeocene and are all sand-rich. They are interpreted as being deposited in a series of submarine channels and lobes on a large submarine fan in a base of slope to basin plain setting. The reservoir sandbodies are interpreted to be laterally discontinuous due to the inherent channelised nature of the depositional systems. However extensive, seismic-scale clastic remobilisation and injection observed within the study area may enhance connectivity. The post-depositional remobilisation and injection also contributes to the low preservation of primary depositional geometries.

The visualisation and interpretation of 3D seismic supported by well data provides better insights into the geometry of complex Paleocene-age depositional systems along the eastern margin of the North Viking Graben. The establishment of a stratigraphic framework and depositional model also allows us to better understand the distribution and controls on the geometry of the large-scale clastic intrusions observed in this part of the basin. The study has implications for the distribution, geometry and connectivity of deep-water reservoir sandbodies in the North Sea and elsewhere.

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Interplay of Fan Fringe Reservoir Deterioration and Hydrodynamic Aquifer: Understanding the Margins of Gas Development in the Ormen Lange Field

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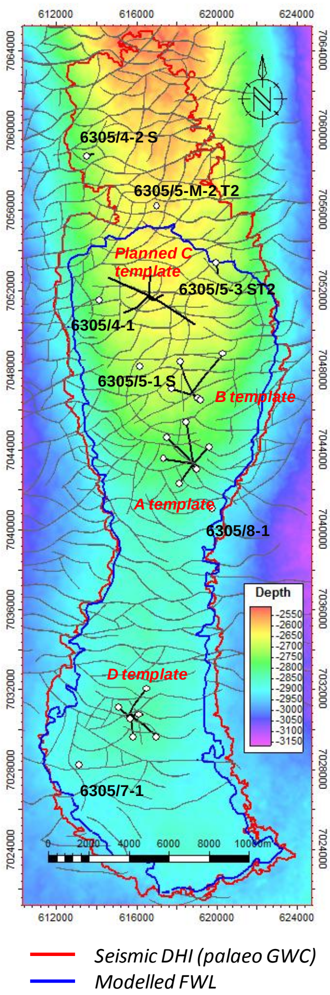


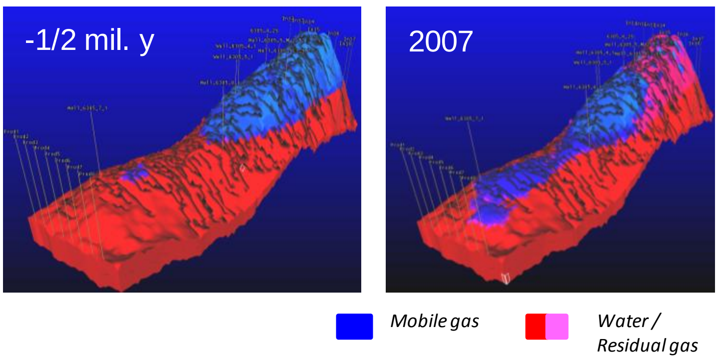
The giant Ormen Lange field was discovered in 1997 and brought on-stream in 2007. The field currently produces gas from 12 wells drilled from three subsea templates.

The accumulation is located approximately 100 km offshore mid Norway, in the Møre basin of the Norwegian Sea. It is a combined structural-stratigraphic trap developed on a flank of a large Eocene-age inversion dome. The field contains two sand-rich turbidite fan reservoirs of late Cretaceous and early Paleocene age. The fans were part of a deep-water depositional system accommodated by approximately north-south oriented slope depressions developed on the rifted margin of the basin. During and soon after deposition, a dense network of faults developed, partially offsetting the reservoirs.

The original outline of the field was defined by a seismic DHI (direct hydrocarbon indicator) interpreted as a gas-water contact on the flanks and a reservoir pinch-out in the north. The initial appraisal campaign confirmed a high net/gross reservoir in the core of the field and close conformance of the gas-water contacts to the DHI. Differences in the depth of the fluid contact were attributed to local perching of water at the sand-shale juxtaposition across faults.

Development plans had to be significantly amended after a monitoring well, drilled 10 km to the north from the core production area, found only residual gas saturation and lower than expected net reservoir thickness. Subsequent appraisal drilling confirmed a gradual deterioration of reservoir quality towards the northeast and the absence of any significant mobile gas accumulation in the northern 20% of the original DHI-defined area of the field.

Modelled gas cap displacement by dynamic aquifer



The results showed previously unrecognized oblique orientation of the younger Egga reservoir in relation to the underlying structural low orientation, probably caused by a progressively decreasing degree of topographic confinement. New fluid fill observations testified a more complex trap and charge history.

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Alvheim Area Depositional Model Enhancement Using Seismic Attributes, Palaeocene – Offshore Norway

Anne M. Schwab, Eric W. Jameson and Kevin L. Stuart , *Marathon Oil Corporation*

The Alvheim Area, offshore Norway (PL203 – Blocks 24 and 25), produces gas and oil from the Palaeocene Heimdal Sandstone Member of the Lista Formation in the Boa, Kameleon, East Kameleon and Kneler Fields. In this area the Heimdal sandstones are between 200m and 400m thick, with Net-to-Gross of over 85%, average porosity of 25% and Darcy range permeabilities. The Heimdal member is composed of turbidite deposits in the Alvheim Area, with the reservoir interval comprising the uppermost few 10s of meters of the sequence. Thin heterolithic sand/shale layers occur at the top of the low relief Alvheim Field structures, and are underlain by thicker, cleaner sandstones. The overlying Lista shales act as the seal to the low relief fields. The Heimdal sandstones are interpreted to have been deposited as compensatory stacked deep-water fan complexes in a Late Palaeocene basin floor setting.

3D reflection seismic data shows each field to be a low relief structure with a clear AVO anomaly of amplitude brightening across the far angles. Recent work with horizon sculpted gathers has allowed the identification of regional AVO variations which probably occur due to differences in the lithology and fluid phase. The hydrocarbon reservoir intervals average between 25 and 35m gross thickness, containing various combinations of oil and gas. Distinct oil and gas AVO responses do not occur. Mapping of the top reservoir bright amplitudes on the far stack has led to the successful discovery and completion of horizontal production wells, but has not aided greatly in the depositional model of the Heimdal sands. The fluid effect overwhelms the underlying acoustic response on the reflection seismic and makes seismic reservoir characterization difficult. This has led to a stochastic reservoir characterization in the field geologic models.

Numerous seismic attributes have been computed along the top reservoir horizon, but only those showing fault/channel edge locations have been useful for the geologic model (i.e. coherency and ant tracking volumes). Recent work on spectral decomposition of a full stack volume across the greater Alvheim Area has been shown to indicate more detailed depositional trends than those of the amplitude attributes along the top reservoir horizon (Figure 1a). The 3D seismic data was reprocessed in 2009, with special attention given to pre-stack processing. Noise cancellation was then preformed on the full stack of the new processing, and this volume was the input for the spectral decomposition into various frequency component volumes, which were then used in red-green-blue blended volumes.

After experimentation with various frequencies, a blend of the 10Hz, 26Hz and 45Hz frequency seismic volumes was found to optimize detail within the upper part of the Heimdal sequence. A depth slice of this volume is seen in Figure 1b, and clearly shows the thicker sand fairways of the fields in the yellow-white colours. Individual channels within the fairways can be seen in the sinuous purple colours, and areas of thinner overbank deposits can also be seen in the fringing blue colours. This blended volume was used to map out the general sand fairways and detailed potential reservoir architectural elements (i.e. channels, sheets, overbank) within the various fields. The spectral decomposition work has shown that the reservoir architecture is slightly different in each field, and this can now be incorporated into the updated geological models of the fields. In addition to the added detail of reservoir architecture, this spectral decomposition work has greatly aided in piecing together the regional depositional history within the area, which is important since the Heimdal sequence is composed of a stack of compensating deep-water turbidite fans. The detail of the spectral decomposition work is currently being incorporated into the updated geological/reservoir models of the Greater Alvheim Area.

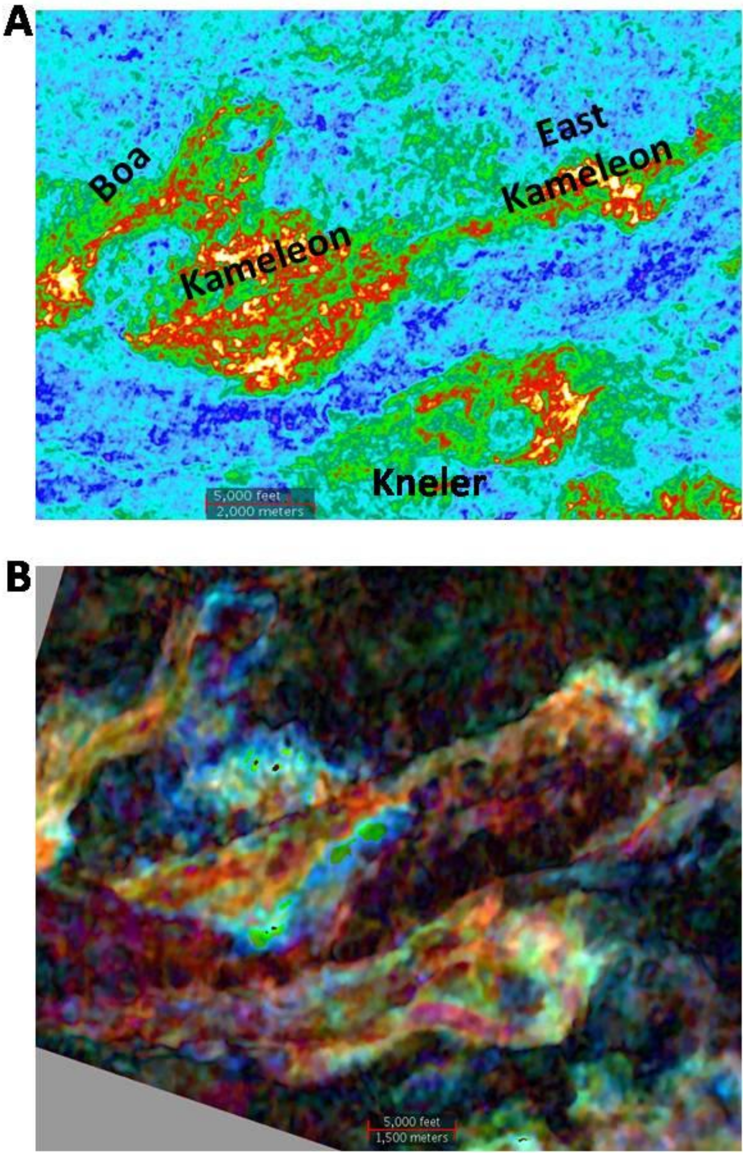

Figure 1: A – RMS Amplitude of Top Reservoir Horizon on a Far Stack Volume. The fields are clearly delineated with the AVO anomaly seen by the large negative amplitudes in red/yellow/light green colours. Boa, Kameleon and East Kameleon Fields contain gas and oil, and Kneler only has oil. B – Spectral Decomposition RedGreenBlue (10-26-45Hz) blend of depth slice within the reservoir. The thicker sand fairways are delineated in the yellow-white colours, with sinuous channels seen in purple colours and thinner overbank deposits in blue colours.

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Biodegradation of Oil in a Tertiary Mass Flow System - Implications for Reservoir Quality and Performance in the Nini East Field, Danish North Sea

Johan Svendsen[1], Niels Schovsbo[2], Henrik Friis[3],

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Biodegradation of shallow buried Tertiary reservoirs is a wide-spread phenomenon within the North Sea, and the resulting mix of gas and oil, as well as the resulting viscous oil, has been a challenge for production from these reservoirs. However, the results of biodegradation are not necessarily only a challenge for production. In this study we present a number of characteristic from the biodegradational process, allowing subtle biodegradation, to be depicted from limited well data. Furthermore, a detailed knowledge of the phenomena resulting from biodegradation, allows for better uncertainty evaluation when deciding whether or not to set a field, impacted by biodegradation, into production.

The Nini East Field, Danish North Sea, was prior to its discovery in 2001, considered to be comparable to the remaining fields of the Siri Fairway. However, drilling of exploration, appraisal and production wells proved otherwise. The field contained significantly more CO2 than the other fields in the Siri Fairway. Furthermore, gas caps (with different gas oil contacts) with fairly dry gas, and dC13 of methane values around -50 ‰, were encountered. Close examination of one of the gas caps showed that oil was present within the gas cap showing that the oil infill pre-dates the generation of gas. Examination of the oil zone showed that oil close to the oil water contact is biodegraded, whereas oil within the main part of the reservoir shows no sign of degradation. The Eocene-Paleocene reservoir of Nini East is a glauconite rich poorly consolidated sandstone, with very high porosity [total porosity 35-38%] and permeabilities [400-2.500 mD], due to the very limited mechanical compaction and chemical diagenesis. However, at the oil water contact (OWC) and a few metres around the OWC, scattered siderite cementation is seen [4-8 vol%], with a dC13 of the carbonate with values around -12 - -7 ‰.

All observations from Nini East show that biodegradation, caused by anaerobic methanogenesis, of the oil has taken place, giving rise to the generation of local gas caps with methane, enrichment of CO2 in the oil and gas, biodegraded oil, and cementations at the oil water contact. The impact of the microbial activity has been severe. The cementation of the oil water contact has been adopted into the reservoir model, production of light gas has challenge the infra structure, high content of CO2 resulted in different steel composition for the Nini East wells.

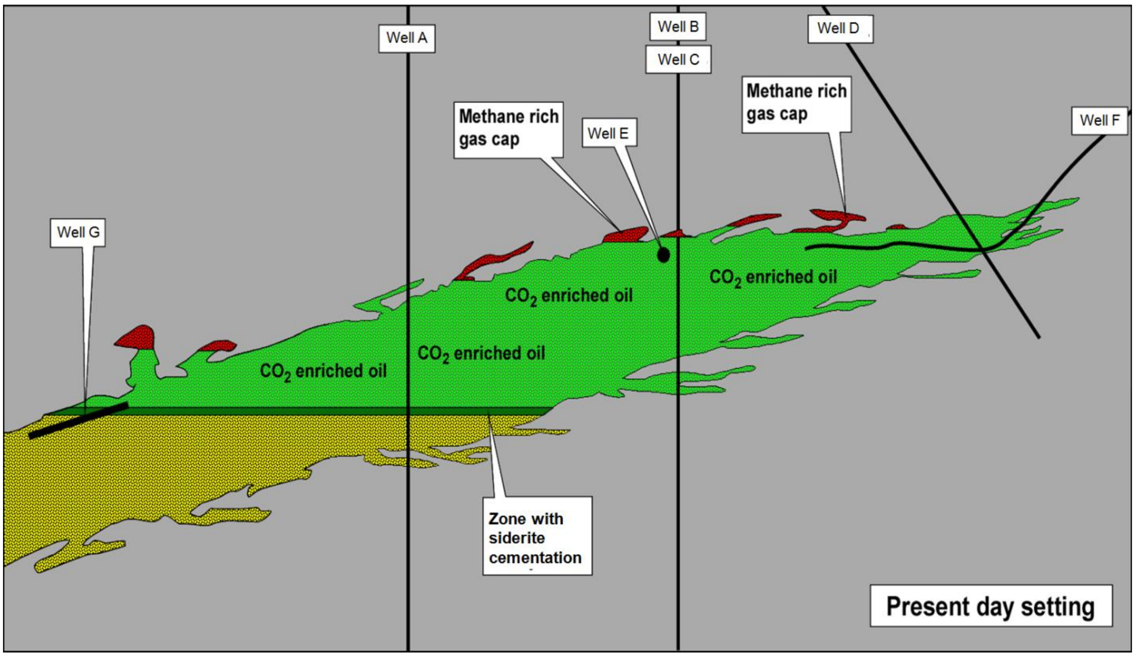

Figure 1: Schematic drawing of the Nini East Field, including the numerous wells used to contrain the Biodegradation Model.

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Alba Field Development

Ian Moore, *Chevron*

As giant oil fields mature, the flow of results from development drilling and production history, together with interpretations of seismic data provides an evolving view of in-place volumes, reservoir architecture and fluid movement through the reservoir. Often, such changes can trigger modifications to asset development plans and, along with economic conditions, revisions to estimates of ultimate recovery.

The development of the Alba Field – a relatively heavy oil (19° API) accumulation lying in an Eocene deepwater channel complex in Block 16/26 of the UK's Central North Sea – has followed a similar pattern. With an estimated 900 mmbls in-place, the reservoir is characterised by thick (350ft), high net-to-gross (80-90%) sands that have extremely favourable reservoir properties. Because of the presence of extensive bottom water and less favourable mobility ratios, the Field has been developed exclusively by horizontal production wells placed high in the reservoir, with pressure support provided by a series of seawater injectors.

The development has involved more-or-less continuous drilling from a fixed Platform in the northern part of the Field and intermittent drilling from a southern, sub-sea drilling centre. Now, after 17 years of production, more than 380 mmbbls of oil have been recovered. During this time, the Operator has applied several key seismic and drilling technologies to address reservoir complexities and reservoir management challenges that have emerged as Field development has progressed. The most significant include:

- A dramatic uplift in imaging the depositional architecture was provided by converted shear wave seismic data (OBC, 1998), revealing an extremely irregular top reservoir and hinting at greater internal complexity that initially modelled,
- Advances in Extended Reach Drilling (ERD) technology enabled a greater number of infill targets to be accessed, whilst geosteering techniques allowed better well placement and horizontal completions using gravel packs improved well reliability,
- Spectacular images of production cones beneath horizontal production wells extracted from a dedicated 4D monitor survey (2008), address the Field's key dynamic uncertainty – where is the remaining oil?

This presentation sets out to describe some of these techniques, their influence on how the asset has been characterised, and their impact on how it has been developed.

Despite this excellent early performance, the Operator continues to seek opportunities to maximise economic recovery – and a long term vision for Alba is to produce more than 500 mmbbls oil. Achieving this vision will be very dependent on effective reservoir management. From a sub-surface perspective, this requires careful piecing together of data that illuminates the depositional architecture with data that reflects a snapshot of the reservoir's complex dynamic behaviour.

A unique challenge for Alba is to adequately handle a 4D signal that originates from long horizontal producers where vertical rather than lateral sweep dominates. Ultimately, reliable reservoir models that capture these valuable insights, based on geologically reasonable interpretations, will be the key tool that enables by-passed oil to be targeted and recovered, as fields such as Alba advance towards their development vision.

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Lochranza - Using Well Results to Explore for Upside

Stijn Konings, Rob Ings, Emma Davies, John McAteer, Ritesh Kumar and Alan McInally,
Maersk Oil North Sea UK Ltd

The Lochranza field is located in block 15/20a, 4km east of Dumbarton (Donan) and 15km northeast of MacCulloch. This Palaeocene oilfield was discovered in 1986 but lay stranded until first oil in January 2010, due to the low relief of the structure and thin oil column. Development was facilitated by the installation of the FPSO "Global Producer III" and the subsurface lessons learned from the adjacent Dumbarton redevelopment.

This talk describes how key learning's obtained from Dumbarton and Lochranza development activities have benefited the identification of Lochranza infill potential. Lochranza well results have highlighted additional complexity and associated challenges. Thinning sands at the margins of the depositional system, small scale sand injection and the appreciation of subtle structural complexity around Lochranza have all resulted in greater interpretation uncertainty. However Lochranza production rates have exceeded expectation and have hinted at the potential of remaining oil not thought to be drained effectively by the current well stock.

The continued use of seismic attribute analysis, evolving conceptual geological models and horizontal well technology has built on the lessons from Dumbarton.

Pragmatism has been applied to Lochranza infill target identification. Empirical observations show that well recovery efficiency is a function of net pay length, stand-off from the OWC and connected STOIIP. Lochranza infill opportunities have been defined by combining STOIIP and recovery efficiency estimates and have been backed up by subsequent simulation modelling.

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The Andrew Sand Member of the Stella Field and Adjacent Areas: The Reservoir Geology of an Event Bed

Simon Smith, Dave Brett, John Horsburgh, Henk Wilms, *Ithaca Energy (UK) Ltd*

The Andrew Sand Member (ASM) of the Lista Formation is a turbidite event bed that forms a thin (25-30 ft) but extensive sheet (30 by 15 km) in Quadrants 29 and 30. Regional lateral continuity is suggested by biostratigraphic data, common RFT pressure gradients and depletion from fields offset by some 10 km. This event bed or “megaturbidite” reflects catastrophic failure of the shelf margin supplying a rare flux of relatively mature marine sand into a predominantly muddy basin.

The Lista Formation of this area shows extensive reworking and is dominated by a series of stacked mass-transport complexes. These comprise basal chalky debrites and thin sands overlain by muddy debrites and slides and slumps of mudstone and siltstone healed by insitu pelagics. Facies distributions have been mapped in the regional well database and combined with seismic attribute analysis. These data suggest that the Lista Formation is strongly influenced by compensational stacking of chalky debrites.

The internal architecture of the ASM is remarkably consistent across large distances. A basal zone of intraclast-rich lithic sandstone is gradationally overlain by parallel-laminated medium to fine-grained sandstone which is then gradationally overlain by very-fine grained sandstones and siltstones with water escape structures. This architecture gives a tripartite distribution of reservoir properties and hydrocarbon saturations: good in the centre, poorer at the top and base. The ASM shows little thickness variation within the Stella Field and shows only subtle indications of laterally declining reservoir properties to the northeast which is the direction in which the Lista Formation thins. This suggests that the diapir at the core of the Stella structure had not created bathymetric relief at the time of ASM deposition.

Accurately modelling the tripartite permeability and hydrocarbon saturations is important. The placement of horizontal wells is also important and will be a challenge in developing Stella. However, simulations suggest that the tripartite architecture enables efficient drainage of this thin sandstone even with moderate penetrations of the central zone

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Poster Presentation Abstracts
(in Alphabetical order)

Determining Forties Sandstone Member Provenance from Heavy Mineral Analysis: Implications for Exploration and Production in the UK Central Graben

Riccardo Borella[1], Ben Kilhams[1], Andy Morton[2,3], Andrew Hurst[1]

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The deep-water sandstones of the Central North Sea are known to derive from Northern Scotland and the Shetlands with two discrete source areas; an axial system from the Northwest (Moray Firth and the Shetland Islands) and a lateral system from the west (Grampian Highlands). Previous work on the Lista and Sele Formations has suggested that garnet assemblage analysis can differentiate between these two source areas. This is of particular importance because proximity to the shelf can determine reservoir quality (grain size, porosity, permeability). Previous work suggests that the lateral fan is an important component in the Sele Formation. It is now possible to test this work using heavy mineral analysis in the Forties Sandstone Member Cycles (T65, T70 and T75).

The analysis has been based on the percentage composition of garnets collected within 16 samples in 4 wells. The results have been matched with known standards from different terrains of Scotland's hinterland and basinal turbidite systems.

It can be shown that the majority of samples have a garnet assemblage associated with an axial turbidite system, showing the typical high-Mg, high-Fe+Mn garnet assemblage associated with the Lewisian/South Harris/Moine terrains. A single sample collected from the well 22/30A-5 shows a different provenance signature, typical of a lateral turbidite system sourced from the Grampian Highlands. However, core analysis suggests that the sample is potentially reworked (by salt diapirism) as is possibly associated with older Lista or Maureen Formation material. This study demonstrates that the Forties Sandstone Member is dominated by axially sourced sandstones with laterally sourced components making up a minor proportion of the Central Graben deepwater deposits. Further work is needed to understand the importance of these findings but there is a significant potential impact on our understanding of reservoir quality distribution.

Sedimentological and Stratigraphic Controls on Low-Resistivity Pay in the Forties System

John Cater, *Ichron Limited*.

Many Forties sandstone reservoirs contain a component of detrital chlorite reworked from the earlier Palaeocene Lista Formation. SEM analysis shows that this chlorite has generally recrystallised to form widespread grain-coating authigenic chlorite. This appears to explain anomalously low-resistivity log response within some oil reservoirs, due to the presence of formation water trapped within the grain-coating clays.

The geographic and stratigraphic distribution of this chlorite component has been investigated as part of a regional biostratigraphic, sedimentological and petrographic study of the Forties system. Preliminary results indicate that Lista reworking was widespread during early Forties times but was more localised during deposition of the Upper Forties sandstones, where most of the oil reservoirs occur. This is largely due to slope instability around salt diapirs during late Forties times, which exposed Lista claystones to reworking whilst elsewhere the Lista was buried under a blanket of earlier Forties sediments.

This analysis indicates that low-resistivity pay zones may be expected where reservoir sands have accumulated in local salt-withdrawal basins. Such mini-basins are characterised by deposition of relatively muddy, heterogeneous-banded sandstones (‘hybrid beds; see Davies *et al*., 2009 and Scott *et al.,* 2010). This is one of several distinctive facies that has been used by Ichron to define and map the depositional setting of several biostratigraphically-calibrated time slices across the UK Central Graben, providing a framework for the prediction of low-resistivity pay.

Volund Field: Development of a Sand Injection Complex, Eocene - Offshore Norway

Anne M. Schwab, Eric W. Jameson, and Ann Townsley, *Marathon Oil Corporation*

The Volund Field lies in the Norwegian sector of the North Sea (Block 24/9). This field produces from a large-scale hydrocarbon-bearing sandstone injection complex in the Early Eocene section. The complex was identified from the seismic, which exhibits a Class 3 bright negative amplitude AVO anomaly. The first exploration well was drilled in 2004 on the Hamsun Prospect, and development drilling was completed in 2010. Volund Field is currently producing oil from four horizontal branches, with one water injector well, and has a common OWC and GOC.

Volund Field is unique in that the entire field is composed of a large-scale sandstone injection complex. The sandstone reservoir was originally deposited in a deep marine turbidite setting within the intra-Sele Formation Hermod Sand Member, and became re-mobilised and subsequently injected into the overlying stratigraphy. The lateral and vertical seal of the 'Injection Trap' are created by the juxtaposition of the injected sands against impermeable surrounding shale and mudstones of the Balder and Hordaland Formations. The Volund Field consists of a deeper central unit of stacked sandstone sills, which are surrounded by shallower, steeper dipping injected sandstone dikes (>20°, often called 'wings'), such that the overall field shape resembles a large-scale 'bathtub' open to the west. The injected sands are an excellent reservoir with consistently high porosity and permeability. Many of the steeply dipping injected dikes appear to have excellent connectivity from the water leg up through the oil leg and into the gas cap.

The hydrocarbon-filled injectite sands at Volund exhibit a Class 3 AVO signature on the Far Offset reflection seismic volume. The seismic has been successfully used to locate horizontal production wells. Seismic geobodies have been extracted and incorporated into the reservoir geomodel to drive the geometry of the injectite features and to populate sands within the injection complex. The current reservoir geomodel also incorporates the vast horizontal well control (~5500m of reservoir section), available core, and outcrop analogue parameters. This Volund Field case study is an excellent, unique example of an economic producing sandstone injection complex.

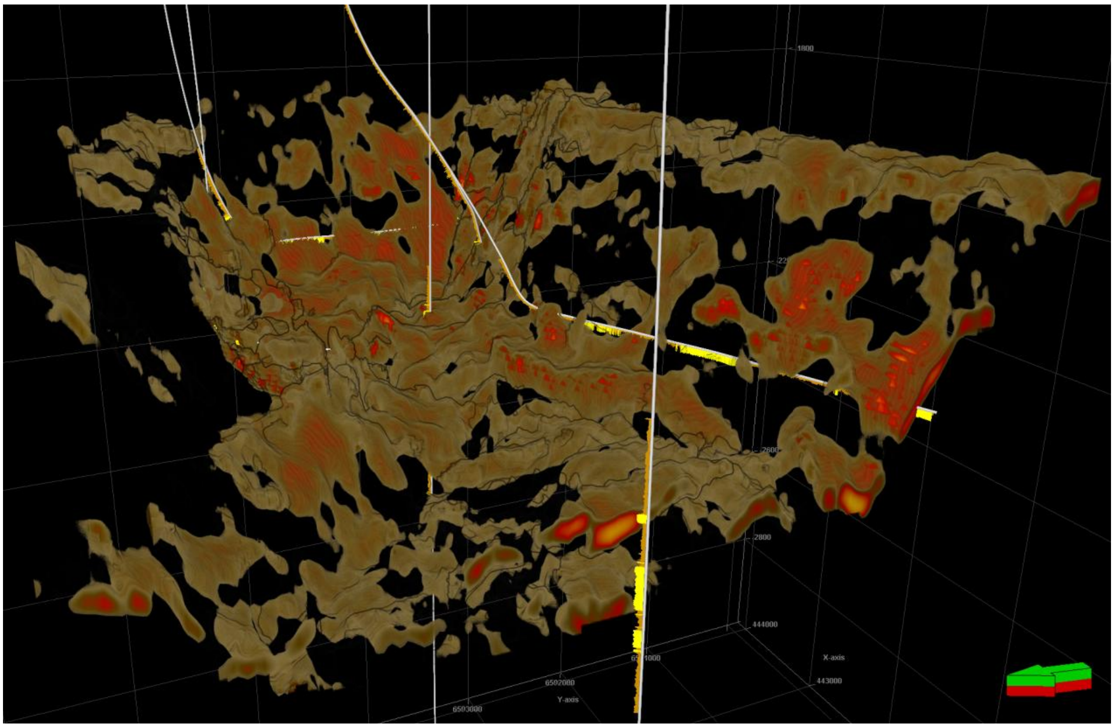

Figure 1: 3D view of seismic opacity cube, which shows the Volund Field Injection Complex. Wells display the Vshale log, with sands colored in yellow. View is looking East.

Seismic Morphology and Sequence Stratigraphy as Tools for the Prediction of Reservoir Facies Distribution; an Example from the Palaeocene and Earliest Eocene of the South Buchan Graben, Outer Moray Firth Basin, U.K. Continental Shelf

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A seismic stratigraphic analysis constrained by well and log data from the Palaeocene and earliest Eocene of the South Buchan Graben, Outer Moray Firth Basin has been undertaken. Two principal depositional sequences corresponding to two regressive/transgressive cycles of second-order relative sea level change have been described in this study. These sequences contain four gross depositional packages corresponding to the Maureen, Lista, Sele and Balder Formations and are further subdivided into eleven sandstone-rich Members deposited in basinal, slope and shelf settings.

Depositional cycle 1 comprises the sandstones of the Maureen, Andrew, Glamis Tuff and Balmoral Members which are expressed as a stacked set of lowstand basin floor fans separated by claystone intervals. This succession represents four cycles of third-order relative sea level change, whose components are separated by claystones representing periods of transgression and highstand in relative third-order sea level. An upwards evolution in fan morphology is observed within deposition cycle 1 and demonstrates that sediment delivery during high uplift/low second-order relative sea level is through sediment bypass, resulting in the deposition of large amalgamated submarine fan geometries, typical of the Andrew Sandstone Member. A reduction in uplift and the rising of second-order relative sea level, however, results in greater pooling of sediment on the shelf providing a linear source of sediment to the basin during shelf failure or lowstand in relative sea level. Fan morphology therefore evolves into a system with a higher mud ratio displaying more channel confinement, typical of the Balmoral Sandstone Member.

Depositional cycle 2 comprises the Sele and Balder Formations of the Moray Group and contains both basinal and shelfal packages as an expression of two cycles of third-order relative sea level change. The Forties Sandstone Member is deposited within highly mounded, levee-confined channels downlapped by a prograding slope succession with well-defined clinoforms and deltaic topsets attributed to the Dornoch and Beauly Formations. The individual parasequences of the prograding wedge are related to eustatic higher-order fluctuations in relative sea level with incision and slope fans, attributed to the Cromarty Sandstone Member, deposited during periods of relative sea level lowstand. Fault-related local subsidence also influenced the stacking patterns observed within the slope clinoforms of the prograding system which display offset stacking southwards into an area where accommodation space had been created.

The lowstand fan complexes of the Early Palaeogene are a proven hydrocarbon play in the Central North Sea and amplitude anomalies, similar to those recently drilled and announced as oil discoveries within the Forties Sandstone Member, have been extracted in the study area. This demonstrates the remaining potential of small, four-way dip closures within the basinal deposits in this area. The identification of basinal and slope features with reservoir potential, along with an understanding of their chronostratigraphic relationship to sealing facies, play an important role in regional play fairway mapping and risk analysis.

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