ES486 CASE STUDY ABSTRACTS

ES486 Petroleum Geology
Peer-to-Peer Learning Model
Journal Article Summaries/Case Study Presentations

(updated March 8, 2017 – Final Draft)

Instructions:

Each student will be assigned a recent case-study journal article on a petroleum geology topic. The objective is to read the case study, digest the information, and create a 12-15-minute powerpoint oral presentation of the topic. The general organization of the presentation will be as follows:

I. Introduction to the topic, with outline of the main presentation headings (introduction should include figures with maps on location of the case study)
II. State of the problem or technique(s) addressed in the article.
III. Methodology
IV. Results
V. Conclusion and Summary

Required Slides: Title Slide, Outline/Overview Slide, Introduction Slide, Conclusion and Summary Slide

Project Deliverables will include:
- -A 12-15-minute powerpoint slide show with images and text on topic, summary of take-home messages
- -1-page handout / outline with key summary bullet points on topic
- -Optional creative video-clip (youtube, etc.) illustrating the techniques or methods

Note: A general rule of thumb is to allow approximately 1 minute per slide of content in a scientific presentation. You presentation should be no more than 10-15 slides for a 12-15-minute presentation, depending on the complexity of the information you are trying to summarize. The presentations will be worth 20 points.

Presentation Schedule TENTATIVE
Download papers at following link:
http://www.wou.edu/las/physci/taylor/es486_petro/ES486_Case_Studies.htm

Week 10 / Tuesday March 14 [HAT PARTY – Wear a Festive Hat, prizes to be awarded for creativity]

2:00-2:10	Taylor Introduction
2:10-2:25	Glynn – McGregor et al., 2012, Nile Basin System
2:25-2:40	Hubbard – Sen, 2013, Petroleum Occurrence Black Sea, Turkey
2:40-2:55	Childers – Holgate et al., 2013, Sedimentology and Stratigraphy of Troll Field, North Sea
2:55-3:10	Lucas – Gaswirth and Higly, 2013, Petroleum Analysis of West Edmund Field, Okla.
3:10-3:25	Cardenas – Tozer et al., 2014, Athabasca Oil Sands
3:25-3:40	Sutter - Hudec et al., 2013, Jurassic Salt Dome Systems, Gulf of Mexico
3:40-3:50	Taylor Conclusion

Week 10 / Thursday March 16 [PAJAMA PARTY – Wear PJs or creative night wear, prizes for style]

2:00-2:10	Taylor Introduction
2:10-2:25	Edwards – Bust et al., 2013, Petrophysical Analysis of Shale Gas Reservoirs
2:25-2:40	Fricke – Neumair et al., 2014, Seal Assessment of Venezuala
2:40-2:55	L. Taylor – Burgess et al., 2013, Identification of Carbonate Build-Ups with Seismic
2:55-3:10	Muncrief – Amour et al., 2013, Carbonate Ramp Reservoirs
3:10-3:25	Jacobus – Johansen, 2013, Seismic Facies Analysis Svalbard
3:25-3:50	Taylor Conclusion

GLYNN

The development of the Nile drainage system: integration of onshore and offshore evidence

Duncan S. Macgregor

Surestream Petroleum and MacGeology Ltd, Davidson House, 2 Forbury Square, Reading, UK
Corresponding author (e-mail: dmacgregor@surestream-petroleum.com)

ABSTRACT: This paper reconstructs drainage systems with outlets close to the present-day Nile system, honouring both onshore and offshore evidence and attempts a source to sink quantification. A large river is evidenced to have extended the length of the Red Sea Hills from Eritrea to the current outlet since the Oligocene. The early route of the river is uncertain through Sudan but a more westerly course is proposed through Egypt. The largest contributor of clastic sediment was the Red Sea Hills, where average erosion of the order of 1200–1500 m is constrained by a combination of Apatite Fission Track Analysis, planation surface analysis, and Red Sea sink volumes. Nubia was a significant supplier of sand-rich sediment during wet periods. This sediment supply pattern contrasts with the present-day situation where the Ethiopian Highlands contribute the vast majority of sediments, this contrast being validated by available mineralogical data. This is a consequence of wetter climates in the past and of the younger Ethiopian topography. The interpretations presented here illustrate the importance of hinterland climate change on clastic supply and allow the reservoir fairways in the Nile Cone to be more precisely mapped out in time and space.

INTRODUCTION

The Nile basin (Fig. 1) is one of the most pertinent regions with which to attempt a source to sink assessment. The study of source to sink relationships presented here, which it is hoped ultimately can be extended across Africa as published databases improve, benefits from a voluminous literature, from the availability of recently published offshore isopach maps, from moderately good controlling data onshore and from an appreciation of the principles of African geomorphology during the Cenozoic erosional cycle, as presented by King (1962) and Burke & Gunnell (2008).

Useful overviews on the principles of erosion and sediment supply are provided by Allen (1997), Hay (1998) and Hay *et al.* (2002). Analyses by these authors propose that the main controls on erosion rate are geology (which tends to be averaged over a wide region, thus diminishing its relative importance), relief (specifically the development and angle of slopes) and climate (maximum intensity of rainfall). Due to its varying topography and climate through time, the Nile represents an ideal laboratory to test these controls.

In this paper, the term 'Nile' is used loosely to refer to any river debouching close to the current river outlet during the Oligocene–Recent period.

PREVIOUS WORK ON THE NILE HINTERLAND

There is a considerable volume of literature debating the geological history of the River Nile, based on onshore geological and geomorphological evidence, with little calibration to offshore sedimentation. Previous interpretations fall into two schools. One school of workers (Butzer & Hansen 1968; De Heinzelin 1968; Wendorf & Schild 1976; Said 1981; Issawi & McCauley 1992) propose that an extended Nile did not connect from Ethiopia, Eritrea and Sudan through to the Mediterranean until at earliest Late Messinian times and, for some authors, not until the Holocene (e.g. Salama 1987, 1997). Evidence presented includes landform and radar analysis supporting a southwesterly flowing river in southern Egypt in Miocene times (that ultimately is proposed to feed the Niger), the apparent immaturity of the current Nile course through central Sudan, and mineralogical data indicating a diminishing contribution from Ethiopian volcanic sources with increased age. A second school of authors (Berry & Whiteman 1968; McDougall *et al.* 1975; Williams & Williams 1980; Burke & Wells 1989; Craig *et al.* 2011; Abdelkareem *et al.* 2012) favour a model by which a 'Blue Nile' and other Ethiopian tributaries originated in the Oligocene and follow varying courses through Sudan and Egypt to reach the current outlet, with Abdelkareem *et al.* (2012) suggesting an easterly course in Egypt during the Oligo-Miocene along the Qena valley and others a more westerly course. Evidence presented by the second school includes the large, though unquantified, sediment volumes in the Nile, which are proposed to be inconsistent with a purely Egyptian hinterland, and difficulties in taking a river westwards to Chad across the Uweinat-Darfur high trend. Both schools seem agreed that, on the basis of the presence of an endemic fauna with no Nilotic elements until *c.* 0.5 Ma in Lake Albert (Pickford & Senut 1994), and of the thickness of sediments in the enclosed Sudd basin of Sudan (Salama 1987), the White Nile (Fig. 1) is a recent river.

The present-day situation (Fig. 1) is summarized by Said (1981) and Woodward *et al.* (2007) who quote hydrological data showing that of water reaching Aswan prior to dam

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HUSBAND

New evidences for the formation of and for petroleum exploration in the fold-thrust zones of the central Black Sea Basin of Turkey

Şamil Şen

ABSTRACT

The central Black Sea Basin of Turkey is filled by more than 9 km (6 mi) of Upper Triassic to Holocene sedimentary and volcanic rocks. The basin has a complex history, having evolved from a rift basin to an arc basin and finally having become a retroarc foreland basin. The Upper Triassic–Lower Jurassic Akgöl and Lower Cretaceous Çağlayan Formations have a poor to good hydrocarbon source rock potential, and the middle Eocene Kusuri Formation has a limited hydrocarbon source rock potential. The basin has oil and gas seeps. Many large structures associated with extensional and compressional tectonics, which could be traps for hydrocarbon accumulations, exist.

Fifteen onshore and three offshore exploration wells were drilled in the central Black Sea Basin, but none of them had commercial quantities of hydrocarbons. The assessment of these drilling results suggests that many wells were drilled near the Ekinveren, Erikli, and Ballıfakı thrusts, where structures are complex and oil and gas seeps are common. Many wells were not drilled deep enough to test the potential carbonate and clastic reservoirs of the İnaltı and Çağlayan Formations because these intervals are locally buried by as much as 5 km (3 mi) of sedimentary and volcanic rocks. No wells have tested prospective structures in the north and east where the prospective İnalti and Çağlayan Formations are not as deeply buried. Untested hydrocarbons may exist in this area.

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AUTHOR

Şamil Şen ~ *Department of Geology, Istanbul University, Avcılar, Istanbul, Turkey; and Technology Transfer Inc., Istanbul Technopolis, Avcılar, Istanbul, Turkey; samilsen@istanbul.edu.tr*

Şamil Şen is a petroleum consultant to international petroleum firms in the Technology Transfer Inc., Istanbul Technopolis, Turkey, and an assistant professor in the Geological Engineering Department of Istanbul University, Turkey. His past and present research concerns conventional and unconventional oil and gas exploration in the Thrace–Black Sea–Caspian Sea basins, and the Middle East–eastern Mediterranean basins. His works have been supported by the Scientific Research Projects Coordination Unit of Istanbul University, the Technology Transfer Inc., Istanbul Technopolis, the Turkish Petroleum Company, and the General Directorate of Petroleum Affairs of Turkey. He received his M.Sc. degree (1994) and Ph.D. (2001) from Istanbul University.

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The AAPG Editor thanks Michael L. Sweet for his work on this paper.

EDITOR'S NOTE

Color versions of Figures 1–12 may be seen in the online version of this article.

C HILDERS

Sedimentology and sequence stratigraphy of the Middle–Upper Jurassic Krossfjord and Fensfjord formations, Troll Field, northern North Sea

Nicholas E. Holgate[1,*], Christopher A.-L. Jackson[1], Gary J. Hampson[1] and Tom Dreyer[2]

[1]*Department of Earth Science & Engineering, Imperial College, London SW7 2BP, UK*
[2]*Statoil UK Ltd, One Kingdom Street, Paddington, London W2 6BD, UK*
**Corresponding author (e-mail: n.holgate09@imperial.ac.uk)*

ABSTRACT: The Middle–Upper Jurassic Krossfjord and Fensfjord formations are secondary reservoir targets in the super-giant Troll oil and gas field, Horda Platform, offshore Norway. The formations comprise sandstones (*c.* 195 m thick) sourced from the Norwegian mainland to the east, that pinch out basinwards into offshore shales of the Heather Formation to the west. Sedimentological analysis of cores from the Troll Field has identified six facies associations, which represent wave- and tide-dominated deltaic, shoreline and shelf depositional environments. Resulting depositional models highlight the complex distribution of depositional environments, and reflect spatial and temporal variations in physical processes at the shoreline, rate of sediment supply and accommodation development. These models are further complicated by the absence of coastal plain facies, which implies that the Troll Field was fully subaqueous during deposition, that shoreline regression was forced by falling sea level or that coastal plain deposits were removed by transgression. Genetic sequences bounded by major flooding surfaces ('series') exhibit laterally uniform thicknesses, implying no major tectonic influence on sedimentation. The recognition of pronounced variability in facies character and stratigraphical architecture emphasize the need for a robust depositional model of the formations in order to drive future exploration in these, and coeval, reservoirs.

INTRODUCTION

The super-giant Troll oil and gas field is located on the Horda Platform on the eastern margin of the Viking Graben, northern North Sea (Fig. 1a), and has produced 220.7 million Sm^3 (1.39 billion barrels) of oil and 391.8 billion Sm^3 (13.84 trillion cubic feet) of gas during 21 years of production since 1990 (NPD 2011). The Troll Field is divided into the Troll West and Troll East accumulations, although pressure communication has been proven between the two accumulations (NPD 2011). Rotated fault blocks define the traps for both accumulations (Fig. 1c) and the reservoir consists of shallow-marine sandstones; production to date has been from the Sognefjord Formation (Oxfordian–Kimmeridgian/Volgian) (Fig. 2). The underlying Fensfjord Formation (Callovian) forms part of the reservoir and has a proven oil column of 6–9 m in the northern part of Troll East (NPD 2011). The Fensfjord Formation also forms a significant reservoir in the Brage Field (Callovian–Oxfordian), which lies 20 km to the SW of Troll (Fig. 1a). The Sognefjord and Fensfjord formations, together with the underlying Krossfjord Formation (Bathonian), form part of the Viking Group, which is situated above the prolific Brent Group (Fig. 2).

The sedimentology of the Krossfjord and Fensfjord formations is poorly understood as they have not been the focus of previous published work, despite the formations containing potentially large reserves. The formations comprise sandstones principally sourced from the Norwegian mainland to the east and pinch out basinwards into the offshore shales of the Heather Formation to the west towards the North Viking Graben (Stewart *et al.* 1995). The development of a detailed sedimentological and sequence stratigraphical model for the Krossfjord and Fensfjord formations is complicated by two factors. First, the sedimentological character, distribution and stratigraphical architecture of shallow-marine sandstones are strongly controlled by spatial and temporal variation in physical processes at and near the shoreline (e.g. wave- v. tide- v. fluvial-dominated processes) (e.g. Gani & Bhattacharya 2007; Ainsworth *et al.* 2011). Second, the geographical partitioning and the relative importance of physical processes can be further complicated in rifts due to fault-block rotation, uplift and subsidence; the sedimentology and stratigraphical architecture of both the Krossfjord and Fensfjord formations may, thus, be anticipated to be complex because they were deposited during the Middle–Late Jurassic rift event (Ravnås & Bondevik 1997).

The aims of this paper are twofold: (1) to produce a high-resolution sedimentological and sequence stratigraphical model for the Krossfjord and Fensfjord formations in the Troll Field; and (2) to determine the dominant shoreline processes and genetic stratigraphical relationships within and between these formations. The work reported herein will improve our understanding of syn-rift sandstone distribution in the northern North Sea, and guide future exploration and production from Krossfjord and Fensfjord reservoirs.

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LUCAS

Petroleum system analysis of the Hunton Group in West Edmond field, Oklahoma

Stephanie B. Gaswirth and Debra K. Higley

ABSTRACT

West Edmond field, located in central Oklahoma, is one of the largest oil accumulations in the Silurian–Devonian Hunton Group in this part of the Anadarko Basin. Production from all stratigraphic units in the field exceeds 170 million barrels of oil (MMBO) and 400 billion cubic feet of gas (BCFG), of which approximately 60 MMBO and 100 BCFG have been produced from the Hunton Group. Oil and gas are stratigraphically trapped to the east against the Nemaha uplift, to the north by a regional wedge-out of Hunton strata, and by intraformational diagenetic traps. Hunton Group reservoirs are the Bois d'Arc and Frisco Limestones, with lesser production from the Chimneyhill subgroup, Haragan Shale, and Henryhouse Formation.

Hunton Group cores from three wells that were examined petrographically indicate that complex diagenetic relations influence permeability and reservoir quality. Greatest porosity and permeability are associated with secondary dissolution in packstones and grainstones, forming hydrocarbon reservoirs. The overlying Devonian–Mississippian Woodford Shale is the major petroleum source rock for the Hunton Group in the field, based on one-dimensional and four-dimensional petroleum system models that were calibrated to well temperature and Woodford Shale vitrinite reflectance data. The source rock is marginally mature to mature for oil generation in the area of the West Edmond field, and migration of Woodford oil and gas from deeper parts of the basin also contributed to hydrocarbon accumulation.

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AUTHORS

Stephanie B. Gaswirth ~ *U.S. Geological Survey, P.O. Box 25046, MS 939, Denver, 80225 Colorado; sgaswirth@usgs.gov*

Stephanie Gaswirth received a B.A. degree in geology from Franklin & Marshall College, an M.S. degree in geology from Rutgers University, and a Ph.D. in geology from the University of Colorado, Boulder. She worked for ExxonMobil Upstream Research Company before joining the U.S. Geological Survey in 2006. She has worked on resource assessments of the Williston and Anadarko basins. Her current work focuses on the Bakken and Three Forks Formations.

Debra K. Higley ~ *U.S. Geological Survey, P.O. Box 25046, MS 939, Denver, 80225 Colorado; higley@usgs.gov*

Debra Higley has been a research geologist with the U.S. Geological Survey for 30 years, preceded by 5 years in uranium exploration. Research includes petroleum resource assessment, petroleum system modeling for Rocky Mountain and mid-continent basins, and reservoir characterization. Higley's M.S. degree in geochemistry and Ph.D. in geology were from the Colorado School of Mines and her B.S. degree in geology was from Colorado Mesa University.

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C Amoents

E&P NOTE

Athabasca oil sands: Megatrap restoration and charge timing

Richard S. J. Tozer, Albert P. Choi, Jeffrey T. Pietras, and Donald J. Tanasichuk

ABSTRACT

The petroleum trap for the Athabasca oil sands has remained elusive because it was destroyed by flexural loading of the Western Canada Sedimentary Basin during the Late Cretaceous and Paleocene. The original trap extent is preserved because the oil was biodegraded to immobile bitumen as the trap was being charged during the Late Cretaceous. Using well and outcrop data, it is possible to reconstruct the Cretaceous overburden horizons beyond the limit of present-day erosion. Sequential restoration of the reconstructed horizons reveals a megatrap at the top of the Wabiskaw-McMurray reservoir in the Athabasca area at 84 Ma (late Santonian). The megatrap is a four-way anticline with dimensions 285 × 125 km (177 × 78 mi) and maximum amplitude of 60 m (197 ft). The southeastern margin of the anticline shows good conformance to the bitumen edge for 140 km (87 mi). To the northeast of the anticline, bitumen is present in a shallower trap domain in what is interpreted to be an onlap trap onto the Canadian Shield; leakage along the onlap edge is indicated by tarry bitumen outliers preserved in basement rocks farther to the northeast. Peripheral trap domains that lie below the paleospillpoint, in northern, southern, and southwestern Athabasca, and Wabasca, are interpreted to represent a late charge of oil that was trapped by bitumen already emplaced in the anticline and the northeastern onlap trap. This is consistent with kimberlite intrusions containing live bitumen, which indicate that the northern trap domain was charged not before 78 Ma. The trap restoration has been tested using bitumen-water contact well picks. The restored picks fall into groups that are

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AUTHORS

Richard S. J. Tozer ~ *BP Canada, 240 4th Avenue SW, Calgary, Alberta, Canada; present address: BP Exploration, 580 Westlake Park Boulevard, Houston, Texas; Richard.Tozer@bp.com*

Richard Tozer is a geologist with 11 years of industry experience. He holds a B.Sc. degree in geology from Imperial College, London, United Kingdom, and a Ph.D. in structural geology from the University of Leeds, United Kingdom. He has worked for BP since 2003 and is currently evaluating exploration opportunities on the Brazil equatorial margin. His research interests include thrust tectonics, passive margin evolution, and arctic geology.

Albert P. Choi ~ *BP Canada, 240 4th Avenue SW, Calgary, Alberta, Canada; Albert.Choi@bp.com*

Albert Choi received a B.Sc. degree in engineering physics from the University of British Columbia and an M.Sc. degree in geophysics from the University of Alberta. He has held various technical and supervisory positions with BP and is currently team leader for regional studies in BP Canada.

Jeffrey T. Pietras ~ *BP Canada, 240 4th Avenue SW, Calgary, Alberta, Canada; present address: Department of Geological Sciences and Environmental Studies, State University of New York at Binghamton, P.O. Box 6000, Binghamton, New York; jpietras@binghamton.edu*

Jeff Pietras is a sedimentologist and stratigrapher who specializes in basin analysis, lacustrine stratigraphy, and hydrocarbon exploration. He received his B.S. degree in geology from Binghamton University, and his M.S. degree and his Ph.D. in geology from the University of Wisconsin–Madison. He has worked regional-scale projects on sedimentary basins around the world for BP.

Donald J. Tanasichuk ~ *BP Canada, 240 4th Avenue SW, Calgary, Alberta, Canada; Donald.Tanasichuk@bp.com*

Don Tanasichuk is a geophysicist working in the regional oil sands team of BP Canada. He has more than 30 years of industry experience working from prospect evaluation to

Summ

Jurassic evolution of the Gulf of Mexico salt basin

Michael R. Hudec, Ian O. Norton, Martin P. A. Jackson, and Frank J. Peel

ABSTRACT

We present a new hypothesis for the Jurassic plate-tectonic evolution of the Gulf of Mexico basin and discuss how this evolution influenced Jurassic salt tectonics. Four interpretations, some based on new data, constrain the hypothesis. First, the limit of normal oceanic crust coincides with a landward-dipping basement ramp near the seaward end of the salt basin, which has been mapped on seismic data. Second, the deep salt in the deep-water Gulf of Mexico can be separated into provinces on the basis of position with respect to this ramp. Third, paleodepths in the postsalt sequence indicate that salt filled the Gulf of Mexico salt basin to near sea level. Fourth, seismic data show that postsalt sediments in the central Louann and the Yucatan salt basins exhibit large magnitudes of Late Jurassic salt-detached extension not balanced by equivalent salt-detached shortening.

In our hypothesis, Callovian salt was deposited in preexisting crustal depressions on hyperextended continental and transitional crust. After salt deposition ended, rifting continued for another 7 to 12 m.y. before sea-floor spreading began. During this phase of postsalt crustal stretching, the salt and its overburden were extended by 100 to 250 km (62–155 mi), depending on location. Sea-floor spreading divided the northern Gulf of Mexico into two segments, separated by the northwest-trending Brazos transform. The eastern segment opened from east to west, leaving the Walker Ridge salient in the center of the basin as the final area to break apart. In some areas, salt flowed seaward onto new oceanic crust, first concordantly over the basement as a parautochthonous province, then climbing up over stratigraphically younger strata as an allochthonous province.

AUTHORS

Michael R. Hudec ~ *Bureau of Economic Geology, University of Texas at Austin, Austin, Texas; michael.hudec@beg.utexas.edu*

Michael R. Hudec received his Ph.D. from the University of Wyoming in 1990. He joined the Bureau of Economic Geology in 2000, where he codirects the Applied Geodynamics Laboratory. His current research interests include the evolution of salt basins and salt-sheet emplacement mechanisms. He is a recipient or corecipient of the Matson, Braunstein, and Levorsen awards of AAPG.

Ian O. Norton ~ *Institute for Geophysics, University of Texas at Austin, Austin, Texas; norton@utig.ig.utexas.edu*

Ian O. Norton received his Ph.D. from the University of Witwatersrand in 1978. He worked for ExxonMobil from 1981 to 2007, primarily in regional analysis and plate-tectonic modeling. After retirement, he joined the University of Texas Institute for Geophysics as a senior research fellow. His current research interests involve the structural evolution of passive continental margins.

Martin P. A. Jackson ~ *Bureau of Economic Geology, University of Texas at Austin, Austin, Texas; martin.jackson@beg.utexas.edu*

Martin P. A. Jackson received his Ph.D. from the University of Cape Town in 1976. After teaching, he joined the Bureau of Economic Geology in 1980 and founded the Applied Geodynamics Laboratory in 1988. He has received several AAPG awards: the Sproule Award, the Matson Award, the Dott Award, and the Berg Outstanding Research Award for his research on salt tectonics.

Frank J. Peel ~ *BHP Billiton Petroleum (Americas) Inc., Houston, Texas; Frank.FJ.Peel@bhpbilliton.com*

Frank J. Peel received his Ph.D. from the University of Oxford. He joined BP in 1985 and BHP in 1996, where he is a senior geoscience advisor, with interest in structural geology and salt tectonics. Current interests involve the structural evolution of passive continental margins, and multiphase fluid flow in hydrocarbon basins. He is a recipient of the Matson Award of AAPG.

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EDWARDS

The petrophysics of shale gas reservoirs: Technical challenges and pragmatic solutions

Vivian K. Bust[1], Azlan A. Majid[2], Joshua U. Oletu[1] and Paul F. Worthington[2]*

[1]*Gaffney, Cline & Associates, Inc., 1300 Post Oak Boulevard, Suite 1000, Houston, Texas 77056, USA*
[2]*Gaffney, Cline & Associates (Consultants) Pte. Ltd, 80 Anson Road, # 31-01C, Singapore 079907*
**Corresponding author (e-mail: pworthington@gaffney-cline.com)*

ABSTRACT: The host rocks of shale gas accumulations act as source, seal and reservoir. They are characterized by complex pore systems with ultra-low to low interparticle permeability and low to moderate porosity. The word 'shale' is used in the sense of a geological formation rather than a lithology, so shale gas reservoirs can show marked variations in rock type from claystones, marlstones and mudstones to sandstone and carbonate lithological 'sweet spots'. The pore space includes both intergranular and intrakerogen porosity. The density of natural fractures varies markedly, and pore throat connectivity is relatively ineffective. Moreover, *in-situ* gas pore volume has to take account of both free and adsorbed gas, an evaluation exercise that is complicated by pronounced variations in water salinity. All these characteristics present major challenges to the process of petrophysical evaluation. The petrophysical responses to these issues are severalfold. First, a broader calibrating database of core measurements is required at key wells, especially as regards mineralogy, porosity and permeability data, shale/mudstone sample analyses, total organic carbon, gas desorption isotherms, and the analysis of extracted formation waters. Second, at least in the key wells, an extended suite of logs should include an elemental analysis log, magnetic resonance imager, electrical micro-imager, and a dipole sonic log. These databases lead to a rock-typing scheme that takes better account of dynamic properties and fracturability. They also allow reservoir partitioning based on exclusivity of empirical interpretative algorithms, e.g. quartz content vs. producibility. These responses comprise key elements of a functional petrophysical system that encompasses fit-for-purpose interpretation methods, such as a pseudo-Archie approach, i.e. the application of the Archie equations with non-intrinsic exponents. This system is presented as a workflow for application in shale gas reservoirs, for which bulk density retains a major influence on computed gas in place. The benefits of this approach are especially strong in reserves reporting of these unconventional gas reservoirs.

INTRODUCTION

In contemporary petrophysical parlance, there are two types of reservoir: those that conform to the implicit assumptions underpinning the work of Archie (1942) and those that do not. The second category includes most of the world's reservoirs. It can be subdivided further into non-Archie conventional reservoirs and unconventional reservoirs (Worthington 2011*a*). Non-Archie conventional reservoirs include those with fresh formation waters, significant shale content, high capillarity, a bimodal pore system, or fractures. In other words, they infringe one or more of the Archie assumptions. Unconventional reservoirs include tight gas sands, coal seam gas reservoirs, gas hydrates, and shale gas reservoirs. Each of these infringes several of the Archie assumptions. At the limit, shale gas reservoirs infringe them all (Table 1), so a different *modus operandi* is required. Yet, the interpretative challenges presented by shale gas reservoirs go even further, because gas-bearing shale deposits co-function as source, seal and reservoir. Therefore, their character contains elements of all three. Thus, for example, shale gas deposits contain kerogen porosity, have very low effective permeability to gas, and yet can show a markedly variable pore character. To be successful, a petrophysical methodology for the evaluation of shale gas deposits has to be founded on approaches that sit outside the conventional range of thinking. This paper presents a synthesis of the technical challenges that face shale gas petrophysics and collates practical solutions based on what is currently known. In so doing, the word 'shale' refers to a complex compositional and grain-size mixture of clay minerals, quartz, carbonates and heavy minerals. These matters cannot be considered in isolation from basin geochemistry and thermodynamics.

APPROACH

The approach recognizes three major influencing factors. First, shale gas petrophysics is on a steep learning curve and it will be

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FRICKE

Integrated charge and seal assessment in the Monagas fold and thrust belt of Venezuela

Martin Neumaier, Ralf Littke, Thomas Hantschel, Laurent Maerten, Jean-Pierre Joonnekindt, and Peter Kukla

ABSTRACT

Conventional basin and petroleum systems modeling uses the vertical backstripping approach to describe the structural evolution of a basin. In structurally complex regions, this is not sufficient. If lateral rock movement and faulting are inputs, the basin and petroleum systems modeling should be performed using structurally restored models. This requires a specific methodology to simulate rock stress, pore pressure, and compaction, followed by the modeling of the thermal history and the petroleum systems. We demonstrate the strength of this approach in a case study from the Monagas fold and thrust belt (Eastern Venezuela Basin). The different petroleum systems have been evaluated through geologic time within a pressure and temperature framework. Particular emphasis has been given to investigating structural dependencies of the petroleum systems such as the relationship between thrusting and hydrocarbon generation, dynamic structure-related migration pathways, and the general impact of deformation. We also focus on seal integrity through geologic time by using two independent methods: forward rock stress simulation and fault activity analysis. We describe the uncertainty that is introduced by replacing backstripped paleogeometry with structural restoration, and discuss decompaction adequacy. We have built two end-member scenarios using structural restoration, one assuming hydrostatic decompaction, and one neglecting it. We have quantified the impact through geologic time of both scenarios by analyzing important parameters such as rock matrix mass balance, source rock burial depth, temperature, and transformation ratio.

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AUTHORS

Martin Neumaier ~ *Institute of Geology and Geochemistry of Petroleum and Coal, Energy and Mineral Resources (EMR), RWTH Aachen University, Lochnerstr. 4-20, 52056 Aachen, Germany; Schlumberger, Ritterstr. 23, 52072 Aachen, Germany; mneumaier@slb.com*

Martin Neumaier received his master's degree in geological reservoirs at the University of Montpellier (France) in 2008. He joined Schlumberger in 2008 as a geologist and is currently preparing a Ph.D. at RWTH Aachen University. Martin's background and research interests are centered on geodynamics and basin evolution, regional and structural geology, petroleum systems modeling and analysis, hydrocarbon exploration, and play to prospect resource evaluation.

Ralf Littke ~ *Institute of Geology and Geochemistry of Petroleum and Coal, Energy and Mineral Resources (EMR), RWTH Aachen University, Lochnerstr. 4-20, 52056 Aachen, Germany; ralf.littke@emr.rwth-aachen.de*

Ralf Littke received his diploma in geology and Ph.D. at Ruhr-University Bochum (Germany). He is professor of geology and geochemistry of petroleum and coal and currently dean of the faculty of Georesources and Material Science at RWTH Aachen University. His research interests include sedimentary basin dynamics, petroleum and source rock geochemistry, porosity and permeability of low-permeability rocks, natural gas geochemistry, organic petrology, petroleum system modeling, and petroleum geology.

Thomas Hantschel ~ *Schlumberger, Ritterstr. 23, 52072 Aachen, Germany; thantschel@slb.com*

Thomas Hantschel received his Ph.D. in numerical modeling in 1987 and worked for IES (Integrated Exploration Systems) as the main developer of the numerical simulator of the PetroMod (Mark of Schlumberger) Basin and Petroleum Systems Modeling software. In 2002, he became the managing director of IES, which was acquired by

L. TAYLOR

Methods for identification of isolated carbonate buildups from seismic reflection data

Peter M. Burgess, Peter Winefield, Marcello Minzoni, and Chris Elders

ABSTRACT

Isolated carbonate buildups (ICBs) are commonly attractive exploration targets. However, identifying ICBs based only on seismic data can be difficult for a variety of reasons. These include poor-quality two-dimensional data and a basic similarity between ICBs and other features such as volcanoes, erosional remnants, and tilted fault blocks. To address these difficulties and develop reliable methods to identify ICBs, 234 seismic images were analyzed. The images included proven ICBs and other features, such as folds, volcanoes, and basement highs, which may appear similar to ICBs when imaged in seismic data. From this analysis, 18 identification criteria were derived to distinguish ICBs from non-ICB features. These criteria can be grouped into four categories: regional constraints, analysis of basic seismic geometries, analysis of geophysical details, and finer-scale seismic geometries. Systematically assessing the criteria is useful because it requires critical evaluation of the evidence present in the available data, working from the large-scale regional geology to the fine details of seismic response. It is also useful to summarize the criteria as a numerical score to facilitate comparison between different examples and different classes of ICBs and non-ICBs. Our analysis of scores of different classes of features suggests that the criteria do have some discriminatory power, but significant challenges remain.

INTRODUCTION

Isolated carbonate buildups (ICBs) are well-known targets for hydrocarbon exploration in both frontier and mature basins. They commonly contain significant accumulations of hydrocarbons.

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AUTHORS

Peter M. Burgess ~ *Shell International Exploration and Production B.V., Rijswijk, The Netherlands; present address: Department of Earth Sciences, Royal Holloway University of London, London, United Kingdom; p.burgess@es.rhul.ac.uk*

Peter Burgess is a professor of sedimentary geology at the Royal Holloway University of London with a Ph.D. in stratigraphic forward modeling from Oxford. His research interests range from dynamic topography and seismic stratigraphy to mechanisms of high-frequency cyclicity in carbonate strata. He worked in research and global exploration for Shell International Exploration and Production between 2002 and 2010 before joining Royal Holloway.

Peter Winefield ~ *Shell International Exploration and Production Inc., 3737 Bellaire Boulevard, P.O. Box 481, Houston, Texas; present address: Sarawak Shell Berhad, Kuala Lumpur, Malaysia; p.winefield@shell.com*

Peter Winefield obtained a Ph.D. in geology in 1999 from the University of Tasmania in Hobart, Australia. He joined Shell International Exploration and Production in 1999 and worked in several assignments in exploration. He is currently a team leader for northwestern Borneo exploration with Sarawak Shell based in Kuala Lumpur and maintains an interest across an eclectic range of technical areas including carbonate exploration geology, carbonate seismic stratigraphy and siliciclastic plays, high pressure–high temperature well operations, pressure prediction, and regional Arctic geology.

Marcello Minzoni ~ *Shell International Exploration and Production Inc., 3737 Bellaire Boulevard, P.O. Box 481, Houston, Texas; m.minzoni@shell.com*

Marcello Minzoni received his M.S. degree in geology from the University of Ferrara, Italy, and his Ph.D. in carbonate geology in 2007 from the University of Kansas. He currently leads the carbonate exploration–scale research theme at Shell in Houston, Texas. His research focuses on carbonate sequence stratigraphy with emphasis on assessing and quantifying the controls on large-scale architecture of carbonate systems.

Muncrief

Outcrop analog for an oolitic carbonate ramp reservoir: A scale-dependent geologic modeling approach based on stratigraphic hierarchy

Frédéric Amour, Maria Mutti, Nicolas Christ, Adrian Immenhauser, Gregory S. Benson, Susan M. Agar, Sara Tomás, and Lahcen Kabiri

ABSTRACT

Considerable effort has been devoted to the development of simulation algorithms for facies modeling, whereas a discussion of how to combine those techniques has not existed. The integration of multiple geologic data into a three-dimensional model, which requires the combination of simulation techniques, is yet a current challenge for reservoir modeling. This article presents a thought process that guides the acquisition and modeling of geologic data at various scales. Our work is based on outcrop data collected from a Jurassic carbonate ramp located in the High Atlas mountain range of Morocco. The study window is 1 km (0.6 mi) wide and 100 m (328.1 ft) thick. We describe and model the spatial and hierarchical arrangement of carbonate bodies spanning from largest to smallest: (1) stacking pattern of high-frequency depositional sequences, (2) facies association, and (3) lithofacies. Five sequence boundaries were modeled using differential global position system mapping and light detection and ranging data. The surface-based model shows a low-angle profile with modest paleotopographic relief at the inner-to-middle ramp transition. Facies associations were populated using truncated Gaussian simulation to preserve ordered trends between the inner, middle, and outer ramps. At the lithofacies scale, field observations and statistical analysis show a mosaiclike

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AUTHORS

Frédéric Amour ~ *Institute of Earth and Environmental Science, Potsdam University, Karl-Liebknecht-Strasse 24-25, 14476 Potsdam-Golm, Germany; amour@geo.uni-potsdam.de*

Frédéric Amour completed his M.Sc. thesis (2007) on Triassic fluvial systems in western Europe at Rennes University, France. He is currently a Ph.D. candidate at Potsdam University, focusing on the investigation and modeling of two opposed platform morphologies—a Jurassic carbonate ramp in Morocco and an isolated platform in Italy. His main research interests include carbonate sedimentology, sequence stratigraphy, and outcrop modeling.

Maria Mutti ~ *Institute of Earth and Environmental Science, Potsdam University, Karl-Liebknecht-Strasse 24-25, 14476 Potsdam-Golm, Germany; mmutti@geo.uni-potsdam.de*

Maria Mutti holds degrees from the universities of Bologna, Wisconsin-Madison, and Milan. Following research at Eidgenössische Technische Hochschule Zürich and Woods Hole Oceanographic Institution, she has held faculty positions at the universities of Southern California and Stuttgart. In 2002, she joined the University of Potsdam as full professor of sedimentary geology. Her research focuses on carbonate systems and the integration of outcrop and subsurface studies.

Nicolas Christ ~ *Faculty of Earth Sciences, Ruhr University, Universitätsstrasse 150, D-44801 Bochum, Germany; Nicolas.Christ@ruhr-uni-bochum.de*

Nicolas Christ is a postdoctoral researcher, whose interests are mainly focused on carbonate sedimentology, geochemistry, and diagenesis. He received his B.Sc. and M.Sc. degrees from the University of Strasbourg, France, and his Ph.D. from the University of Bochum, Germany. Nicolas is currently working as a researcher at the University of Bochum.

Adrian Immenhauser ~ *Faculty of Earth Sciences, Ruhr University, Universitätsstrasse 150, D-44801 Bochum, Germany; adrian.immenhauser@rub.de*

Adrian Immenhauser presently holds the Chair for Sediment and Isotope Geology at Ruhr University. His main research interests include carbonate sedimentology, diagenesis, and inorganic geochemistry. He received his diploma and Ph.D. from Bern University, Switzerland. Adrian has been the president of the Stratigraphy, Sedimentology, and Paleaontology Division of European Geosciences Union, organized the International Association of Sedimentologists and Society for Sedimentary Geology-Central European Section conferences, and is the associate editor of several journals.

Gregory S. Benson ~ *ExxonMobil Upstream Research Company, P.O. Box 2189 URC-SW 639, Houston, Texas 77252; Gregory.S.Benson@ExxonMobil.com*

Greg Benson is a senior research geologist at ExxonMobil Upstream Research Company in Houston, Texas. He received his B.Sc. degree from the University of Southern California (1979) and his M.Sc. degree from the University of Arizona (1981). His interests include geomodeling, field studies, outcrop studies, internal consulting, mentoring, and teaching. Currently, Benson investigates new approaches to the geocellular modeling of fluvial systems.

Susan M. Agar ~ *ExxonMobil Upstream Research Company, P.O. Box 2189 URC-SW 639, Houston, Texas 77272; susan.m.agar@exxonmobil.com*

Susan Agar is the director of the ExxonMobil (FC)^2 Alliance at the ExxonMobil Upstream Research Company, Houston, and is an honorary professor at Heriot-Watt University, Scotland. During her career in academia and industry, she has published on microstructural processes, deformation and fluid flow in accretionary prisms, rift tectonics, mid-ocean ridges and ophiolites, and flow in fractured reservoirs. She holds a Ph.D from Imperial College, London, and an M.A. degree in business administration from the Wharton School, University of Pennsylvania. Agar maintains a strong interest in promoting innovation through industry-academic interactions.

Sara Tomás ~ *Institute of Earth and Environmental Science, Potsdam University, Universitätsstrasse 150, D-44801, Potsdam-Golm, Germany; stomas@geo.uni-potsdam.de*

Sara Tomás received geology degrees from the University of Zaragoza (M.Sc.) and the University of Barcelona (Ph.D.), Spain. She is currently working at the University of Potsdam (Germany)

distribution that was simulated using a fully stochastic approach with sequential indicator simulation.

This study observes that the use of one single simulation technique is unlikely to correctly model the natural patterns and variability of carbonate rocks. The selection and implementation of different techniques customized for each level of the stratigraphic hierarchy will provide the essential computing flexibility to model carbonate settings. This study demonstrates that a scale-dependent modeling approach should be a common procedure when building subsurface and outcrop models.

INTRODUCTION

The investigation of outcrop analogs is a key research tool for the improvement of carbonate reservoir characterization and modeling of subsurface hydrocarbon fields. Outcrop studies provide insights into the distribution and morphology of geologic bodies across a broad range of scales from tens of kilometers down to micrometer-scale features (Kerans et al., 1994; Kjonsvik et al., 1994; Eaton, 2006; Mikes and Geel, 2006; Jones et al., 2008, 2009). One of the current challenges is the integration of various scales of geologic data and concepts into a single three-dimensional (3-D) model (Jones et al., 2009).

Within carbonate systems, facies associations across carbonate platforms and ramps (1–10 km [0.6–6.2 mi]) display gradational and ordered trends between neighboring depositional domains. In contrast, the spatial arrangement of lithofacies (1–100 m [3.3–330 ft]) shows a mosaiclike distribution pattern lacking clear and regular trends in facies-to-facies transitions (Wright and Burgess, 2005). A lithofacies mosaic appears to result from somewhat random processes during the deposition and preservation of carbonate sediments (Burgess, 2008). Each level of the stratigraphic hierarchy displays different distribution patterns, which requires a specific modeling technique designed to reproduce its unique characteristics (Falivene et al., 2006). Accordingly, the modeling of carbonate outcrop should involve the combination of various techniques to accommodate the scale-dependent nature of geologic heterogeneity.

Most of the previous modeling studies applied one single simulation method to model carbonate rocks. These methods span from surface-based modeling (Adams et al., 2005; Sech et al., 2009; Verwer et al., 2009) to interactive facies modeling (Willis and White, 2000; Aigner et al., 2007; Palermo

JACOBUS

GEOLOGIC NOTES

Composition of seismic facies: A case study

Ståle Emil Johansen

ABSTRACT

In this case study, we used simulated seismic data from outcrops on Svalbard to analyze what seismic facies are composed of, what the dominating factors in forming the facies are, and which consequences this has for the interpretation results. Seismic facies analyses can be used to interpret environmental setting, depositional processes, and lithology. Here, we found that noise is the most important factor in forming the seismic facies. Noise is defined as all reflections that cannot be ascribed directly to the reservoir model. Effects from overburden and processing dominated, and the low-frequency content of the seismic section complicated the seismic facies analyses. The main reason for this is that the analysis relies heavily on identified internal patterns and low-angle terminations. Such patterns and terminations are easily created by the seismic method itself, by overburden effects, and by artifacts generated when processing the data. External form, strong amplitudes, and continuous reflections are robust seismic observations, whereas the internal pattern and terminations are commonly deceptive. Identification of boundaries based on predefined patterns of terminations does not work here, and uncritical use of seismic facies analysis in this interpretation case will create wrong reservoir models. Because of the size of the outcrops, the results from this analysis are relevant for reservoir-scale seismic interpretation and detailed interpretation for prospect evaluation in mature basins. For seismic interpretation at a more regional scale, it is probably less relevant.

AUTHOR

Ståle Emil Johansen ~ *Norwegian University of Science and Technology, Department of Petroleum Engineering and Applied Geophysics, Trondheim, Norway; stale.johansen@ntnu.no*

Ståle Emil Johansen is a professor in applied geophysics at the Institute of Petroleum Engineering and Applied Geophysics, Norwegian University of Science and Technology. His current research is focused on geophysical expressions of subsurface terrains and the development of sedimentary basins in the Arctic region. Before joining the university, he worked for Statoil and Electromagnetic Geoservices (EMGS).

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