TRƯỜNG ĐẠI HỌC MỎ - ĐỊA CHẤT

KỶ YẾU

Hội nghị Khoa học - Đào tạo Địa chất Dầu khí
nhân dịp kỷ niệm 45 năm thành lập Bộ môn Địa chất Dầu khí

Hà Nội, ngày 15 tháng 9 năm 2022

LỜI GIỚI THIỆU

Bộ môn Địa chất Dầu khí được thành lập ngày 10 tháng 11 năm 1977 theo Quyết định số 1239/TCCB của Hiệu trưởng Trường Đại học Mỏ - Địa chất tại Phổ Yên, Bắc Thái (nay là tỉnh Thái Nguyên). Sự ra đời của Bộ môn Địa chất Dầu khí là cơ sở cho sự ra đời của Khoa Dầu khí. Trải qua 45 năm xây dựng và phát triển, Bộ môn Địa chất dầu khí đã không ngừng lớn mạnh và trở thành cơ sở lớn nhất của cả nước đào tạo đội ngũ cán bộ khoa học kỹ thuật (trình độ kỹ sư, thạc sỹ, tiến sỹ) chuyên ngành Địa chất dầu khí.

Bộ môn được nhà trường giao cho đào tạo từ khóa 22 (1977-1982), tính đến nay đã đào tạo được 21 tiến sỹ, 08 thạc sỹ và 805 kỹ sư. Trong số các cựu sinh viên, học viên cao học, nghiên cứu sinh được đào tạo từ Bộ môn đã có nhiều người trở thành các nhà khoa học có uy tín, các cán bộ có chuyên môn vững vàng và có nhiều người đang công tác, giữ nhiều vị trí chủ chốt trong ngành dầu khí ở khắp mọi miền của tổ quốc, đóng góp xứng đáng trí tuệ và công sức của mình cho sự phát triển bền vững của đất nước.

Để ghi nhận thành tựu trong 45 năm qua cũng như tri ân đóng góp của các thế hệ thầy và trò đối với sự phát triển của Bộ môn Địa chất Dầu khí, Trường Đại học Mỏ - Địa chất tổ chức Hội nghị Khoa học – Đào tạo Địa chất dầu khí vào ngày 15/9/2022. Hội nghị đã thu hút được sự quan tâm về chuyên môn của nhiều nhà khoa học trong Trường và ở các cơ sở sản xuất, viện nghiên cứu về các lĩnh vực chuyên môn:

- Địa hóa đá sinh;
- Địa chất khu vực, tiến hóa bể trầm tích và hệ thống dầu khí;
- Đặc trưng và mô hình hóa tầng chứa;
- Hiệu suất của giếng và kỹ thuật tầng chứa;
- Nâng cao hệ số thu hồi dầu;
- Thăm dò và khai thác mỏ, nhiên liệu phi truyền thống

Trong tổng số 20 bài viết gửi về để tham dự hội nghị khoa học, Ban tổ chức hội nghị, Ban khoa học và Ban biên tập đã lựa chọn và tổ chức phản biện 16 bài viết theo quy định của Tạp chí KHKT Mỏ - Địa chất. Vì số lượng trang in Số chuyên đề tạp chí **"Advanced Petroleum Geoscience Studies"** có hạn nên tất cả tóm tắt bài báo được chúng tôi biên tập thành cuốn Kỷ yếu Hội nghị Khoa học - Đào tạo Địa chất Dầu khí nhân dịp kỷ niệm 45 năm thành lập Bộ môn Địa chất Dầu khí.

Để có được những kết quả trên, ngoài sự phấn đấu không mệt mỏi của các cán bộ đã và đang công tác tại Bộ môn Địa chất Dầu khí, sự quan tâm giúp đỡ của

Khoa và Nhà trường còn có sự hỗ trợ và hợp tác của các đơn vị khác trong trường cũng như sự quan tâm, ủng hộ của các cơ quan, đơn vị ngoài cơ sở sản xuất, của các thế hệ cựu sinh viên, cựu nghiên cứu sinh của Bộ môn. Nhân dịp kỷ niệm 45 năm thành lập, Bộ môn Địa chất Dầu khí trân trọng cảm ơn sự hợp tác và giúp đỡ vô cùng to lớn đó.

Trân trọng,

TRƯỞNG BAN BIÊN TẬP
TRƯỞNG BỘ MÔN ĐỊA CHẤT DẦU KHÍ

TS. PHẠM VĂN TUẤN

BAN TỔ CHỨC HỘI NGHỊ

Trưởng ban: GS.TS. Trần Thanh Hải

Phó trưởng ban: PGS.TS. Nguyễn Thế Vinh

Thư ký: TS. Phạm Văn Tuấn

Ủy viên Ban tổ chức:

Lê Ngọc Ánh, TS. Nguyễn Thị Minh Hồng, TS. Nguyễn Minh Hòa

BAN KHOA HỌC

Trưởng ban: GS.TS. Trần Thanh Hải

Phó trưởng ban: PGS.TS. Nguyễn Thế Vinh

Thư ký: TS. Phạm Văn Tuấn

Ủy viên Ban Khoa học

TS. Trịnh Xuân Cường	PGS.TS. Hoàng Văn Long	TS. Phan Từ Cơ
TS. Đặng Ngọc Quý	PGS.TS. Nguyễn Trọng Tín	TS. Lê Ngọc Ánh
KS. Phạm Xuân Sơn	PGS.TS. Hoàng Văn Quý	TS. Nguyễn Minh Hòa
ThS. Nguyễn Lâm Anh	TS. Trần Như Huy	
TS. Nguyễn Thanh Tùng	TS. Nguyễn Thị Minh Hồng	

BAN BIÊN TẬP NỘI DUNG

Trưởng Ban biên tập: TS. Phạm Văn Tuấn

Thư ký Ban Biên tập: TS. Nguyễn Minh Hòa

Ủy viên Ban Biên tập:

TS. Lê Ngọc Ánh, TS. Nguyễn Thị Minh Hồng,

ThS. Nguyễn Duy Mười, ThS. Bùi Thị Ngân

CHƯƠNG TRÌNH
HỘI NGHỊ KHOA HỌC - ĐÀO TẠO ĐỊA CHẤT DẦU KHÍ
LỄ KỶ NIỆM 45 NĂM THÀNH LẬP BỘ MÔN ĐỊA CHẤT DẦU KHÍ

Thời gian : **Từ 8h00 thứ Năm ngày 15 tháng 09 năm 2022**

Địa điểm : **Hội trường 300, Trường Đại học Mỏ - Địa chất, Số 18 Phố Viên, Phường Đức Thắng, Quận Bắc Từ Liêm, Hà Nội**

8h00 - 10h00	Đón tiếp và đăng ký đại biểu
8h30 - 8h35	Khai mạc Hội nghị khoa học - đào tạo Địa chất Dầu khí
8h35 - 8h50	*Công tác đào tạo Địa chất dầu khí và định hướng phát triển trong giai đoạn mới.* Phạm Văn Tuấn, Trưởng Bộ môn Địa chất Dầu khí (HUMG)
8h50 - 9h05	*Chuyển đổi số trong thăm dò và khai thác dầu khí.* Nguyễn Anh Đức, Ban Chiến lược (PVN)
9h05 - 9h20	*Đào tạo, nghiên cứu tìm kiếm thăm dò và khai thác dầu khí ở Viện Dầu khí Việt Nam thích ứng với chiến lược chuyển đổi số của Tập đoàn Dầu khí Việt Nam đến năm 2025, định hướng đến năm 2030.* Nguyễn Thanh Tùng, Phó viện trưởng Viện Dầu khí Việt Nam (VPI)
9h20 - 9h50	Giải lao, Poster Presentation
9h50 - 10h05	Văn nghệ chào mừng Lễ kỷ niệm 45 năm thành lập Bộ môn
10h05 - 10h10	Tuyên bố lý do, giới thiệu đại biểu
10h10 - 10h25	Báo cáo 45 năm đào tạo và nghiên cứu khoa học của Bộ môn Địa chất Dầu khí
10h25 - 10h35	Phát biểu của Lãnh đạo Nhà trường
10h35 - 10h55	Tham luận của các đại biểu; trao tài trợ cho Hội nghị
10h55 - 11h05	Phát biểu của đại diện cựu sinh viên
11h05 - 11h15	Tri ân lãnh đạo Nhà trường, Trưởng Khoa, lãnh đạo Bộ môn qua các thời kỳ
11h15 - 11h25	Phát biểu cảm ơn của Trưởng Bộ môn Địa chất Dầu khí
11h25 - 11h45	Bế mạc, chụp ảnh lưu niệm
11h45	Tiệc mừng

HỘI NGHỊ KHOA HỌC - ĐÀO TẠO ĐỊA CHẤT DẦU KHÍ

Mục lục

Thermal maturity modelling for the source rocks in blocks 10 and 11.1, Nam Con Son basin

Le Hoai Nga [a], Pham Thi Dieu Huyen [a], Nguyen Thi Tuyet Lan [a]

[a] *VietNam Petroleum Institute, 167 Trung Kinh, Yen Hoa, Cau Giay, Ha Noi.*

Abstract

Blocks 10 and 11.1 are located at the western boundary of the Nam Con Son Basin, offshore southern Vietnam. Hydrocarbon shows have been encountered in many wells as the Gau Chua, Ca Cho, Gau Ngua, Phi Ma, Than Ma…. In the Ca Cho and Gau Ngua fields, the oil and gas were discovered in Miocene sandstone reservoirs and in fractured granite basement. The Cau and Dua formations are active source rocks in this area. Oil and gas discovered in wells were generated from coal and coaly claystone sediments which deposited under oxidation conditions to weak reducing in fluvio-delta to estuarine environments, in which land plants develop very abundantly. The 2D modeling results suggested that hydrocarbons discovered in the study area mainly derived from the local source rocks. The large quantity of hydrocarbons yields from source rocks in deeper part of southeastern kitchen migrated both vertically and laterally into the overlaying formations. Hydrocarbon strongly migrated lost through open fault. Prospects located near kitchen can trap hydrocarbons if they have a good seal. Block 10 and western block 11.1 face high risk of hydrocarbon charge due to the distance from the kitchen, weak top seal and fault seal. Of seal scenario, the composition of hydrocarbons accumulated in GC structure contains 87.5% volume of liquid and 12.5% volume of gas that derived from local Oligocene source rock. The composition of hydrocarbons in accumulation in CT structure of contains 99% volume of liquid and 92.5% volume of gas that derived from local Oligocene source rock.

Key words: *Block 10&11.1, Nam Con Son basin, source rocks, modelling, coal and coaly claystone.*

Depositional environments of the Miocene sediments in northern Song Hong Basin

Tong Duy Cuong [a], Hoang Van Long [a], Bui Viet Dung [a], Pham Thi Dieu Huyen [a], Nguyen Thanh Tung [a]

[a] *Vietnam Petroleum Institute, Hanoi, Vietnam*

Abstract

Northern Song Hong Tertiary Sedimentary Basin is a classic case study of a pull-apart basin in Southeast Asia, whose formation was controlled by the India-Eurasia collision, sinistral and dextral strike-slip motion of the Ailao Shan-Red River Shear Zone and Opening of the East Vietnam Sea during the Cenozoic. Unlike the central and southern parts of the basin, the northern Song Hong Basin experienced a very strong inversion during the Late Miocene. This rapid uplift of the region has led to significantly change in lithofacies and sedimentary environments, which are now still poorly understood. This uncertainty is considered one of the main challenging in the prediction of the non-structural traps in the region.

The recent results derived from well logging and 2D/3D seismic interpretation allowed us to define the Miocene formation in northern Song Hong Basin, which are subdivided into three substrata, namely: The Lower, Middle and Upper stratum, which are characterized by typical characteristics of lithology and depositional environments. The Lower Miocene formation is dominated by deltaic environment at the bottom, transitioning to the overlying shelf environment. Lithology of the section varies from coarse-grained sediment (sandstone) to fine grained material such as shale and mudstone upward; The Middle Miocene stratum demonstrate sandier, coalic materials of the delta plain and delta front environments intercalated with swampy shale; In contrast, the Upper Miocene section is characterized by more fluvial and nearshore elements. It is illustrated by presence of the channel-filled sand bodies and mouth/longshore sand bars. These sand bodies demonstrate good porosity and horizontal permeability, which are considered to be good potential reservoir for both structural and non-structural traps in the Miocene formation.

Key words: *Paleo-environment, seismic facies, Northern Song Hong Basin*

Application of artificial neural network and seismic attributes to predict the distribution of Late Oligocene sandstones in the Cuu Long basin

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Abstract

Artificial neural network (ANN) has been widely applied in the oil and gas exploration and production. This study presents the results of prediction the distribution of Late Oligocene sandstones in the Cuu Long basin based on the application of artificial neuron network (ANN) and seismic attributes. The authors used unsupervised neural network (UNN) and UNN methods constantly associated with the principal component analysis (PCA) to divide seismic facies. Seismic attributes such as RMS, Frequency, Envelope, RAI, Phase, Sweetness, Amplitude, t-Attenuation were analyzed and selected as input for the ANN training and testing process. Comparing the results of seismic facies classification by UNN method and by UNN combined with PCA, it can be seen that the UNN combined with PCA will help reduce noise in seismic data better than UNN only. The research results have identified the distribution of Late Oligocene potential sandstones in the study area in the Cuu Long basin, which are mainly concentrated in the slopes or a large lake, with the direction of sediment transport from the West and Northwest.

Key words: *Unsupervised neural network, Principal component analysis, seismic attribute, facies, reservoir, Cuu Long basin*

Prediction of carbonate rock facies from core probe permeability measurements and well log data: a case study from carbonate reservoirs, Phu Khanh Basin

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Abstract

Probe permeameter (also known as Mini-permeameter) has been widely used in many field and laboratory applications where in-situ measurements and spatial distributions of permeability are needed. Mini-permeameter measurements have become popular techniques for collecting localized permeability measurements in both laboratory and field applications. It is designed to obtain fast, cheap, intensive and non-destructive permeability measurements and to describe the spatial arrangement of permeability. Currently the probe permeability meter is designed and manufactured as a portable air permeability for field applications and to be used in outcrop and core samples. In this instrument, the permeability is measured by air that flows from the samples to be measured into an air chamber through the vacuum created by increasing the volume of the chamber.

In carbonate reservoirs, permeability predicted from pure porosity-permeability empirical relationship is often difficult due to complex rock pore systems leading to poor porosity-permeability relations. Once the relationships between permeability and textural rock properties are clearly established in carbonates, they can provide better permeability predictions from porosity data. Rock texture is an important parameter for the understanding of the porosity and permeability characteristics of carbonate reservoirs.

In addition to predicting carbonate rock facies from routine core plug porosity and permeability measurements, there is an approach to determine carbonate reservoir facies based on core plug probe permeability. The results of the probe permeability measurements, in this paper, can be used in combination with the porosity values derived from the well logs to classify and predict rock facies in carbonate cored or uncored reservoirs in Phu Khanh basin.

Key words: *Permeability, Probe Permeameter, Petrophysics, carbonate rocks*

Application of deterministic fault-seal analysis for fault-bounding trap: a case study in Than Nong 1B prospect, Block 05-1(a), Nam Con Son basin, offshore Vietnam

Truong Tuan Anh [a], Le Trung Tam [a], Dang Duc Nhan [a], Do Anh Tuan [a], Lai Quoc Lap [b], Nguyen Tien Hoang Lan [a]

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[b] *Independent researcher, Vietnam*

Abstract

Fault-seal analysis has long been applied for predicting potential hydrocarbon column for mitigating risk in exploration and appraisals. Than Nong 1B structure in Block 05-1(a), located nearby Dai Hung field, is a fault-bounding structure; thus, the fault seal capacity plays a major role in trapping hydrocarbon. In this study, the H50 reservoir is taken as an example of how fault-bounded prospects are evaluated in Block 05-1(a). For the case of Than Nong 1B, to meaningfully determine the potential of the structure, the fault geometric analysis is conducted to fully understand the 3D geometry of the structure. Moreover, vertical displacement of the faults is inspected to ensure the quality of input data and to understand how faults and horizons affect each other. After structural description conducted, the study applies all common methods of fault-seal analysis from the 1980s to the newest workflow published in 2016, such as 3D sand-shale juxtaposition analysis, SGR analysis, height-column-prediction algorithms by Yielding et al. (2010). The results of these methods are then combined by using Trap Analysis workflow, proposed by Peter Bretan in 2016, to determine a unique location of fault leak point defining the trappable hydrocarbon column of the structure. The results suggest that the faults in Than Nong 1B prospect are able to hold a maximum column of 183m hydrocarbon in H50 reservoir, significantly higher than the column of 125m hydrocarbon defined by Fault-leak point. Furthermore, this study also proves that the Trap Analysis is an effective method for evaluating structures with high level of fault linkage.

Key words: *Fault seal analysis, Trap analysis, Hydrocarbon column, Prospect evaluation, Fault-bounding structures.*

Improving carbonate reservoir characterization by applying rock typing methods: a case study from the Nam Con Son Basin, offshore Vietnam

Ha Quang Man [a], Nguyen Minh Hoa [b], Bui Viet Dung [c], Nguyen Viet Hong [d], Truong Khac Hoa [a], Pham Quy Ngoc [c]

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Abstract

Understanding the permeability-porosity relationships is the key to improving reservoir prediction and exploitation especially in carbonate reservoirs, which are known for their complex textural and diagenetic variation. Rock type classifications have long been proven to be an effective technique for establishing permeability- porosity relationships, enhance the capability to capture the various reservoir flow behavior and prediction for uncored reservoir zones.

This study highlights some of those practical and theoretically-correct methods, such as Hydraulic Flow Unit (HFU); Global Hydraulic Element (GHE), Winland's R35 method, Pittman method, Lucia method. They are proposed and tested for identification and characterization of the rock types using a database of 555 core plugs from the Miocene carbonate reservoir in the Nam Con Son basin. It is a large isolated carbonate build-up structure which were deposited within a shallow marine platform interior and are dominated by coral, red algal and foraminiferal packstones, wackestones and grainstones. Hydrocarbons in this reservoir have been found in the upper most part of the late Miocene formation.

Conventional core data were first used to define and display the cross plot of permeability and porosity. Different charts and cut-off thresholds were used to classified, defined number of rock type and the linear and non-linear equations were established. The predicted core permeability was calculated using different methods and compared with the actual core permeability for each rock type.

The predicted reservoir rock type and permeability predictions of HFU method was recognized to give better matching of measured core permeability with coefficient of more than 89%.

Key words: *Rock type; permeability; carbonate; Miocene; Nam Con Son basin*

3D dynamic fault sealing capacity modelling to improve history matching: a case study in Oligocene reservoir, Tay Ho Field, Blocks A, Cuu Long Basin, Offshore Vietnam

Vu Viet Hung [a], Nguyen Duc Dong [a], Phan Phuoc Gia [a], Le Minh Vu [a], Ninh Hoang Hai [a]

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Abstract

Fault transmissibility multipliers are a simple way of accounting for the effects of faults on fluid flow across fault plans in history matching of production simulation models. Fault transmissibility multipliers can be calculated using parameters such as fault clay, fault smear, thickness, and permeability. In general, fault transmissibility can be calculated empirically using some host rock properties such as SGR, smear, fault throw, displacement, fault zone thickness, and fault permeability.

In this study, three emperical methods given by Manzocchi et al. (1999), Jolley et al. (2007), and Sperrevik et al. (2002) have been applied to the Oligocene sandstone reservoir, Tay Ho Field. The Oligocene reservoir is a complicated sandstone that was deposited in alluvial-fluvial and lacustrine environments, trapped by both stratigraphic and structural types, sandbody isolated by multi-activated faults. Fault sealing is one of the key factors controlling hydrocarbon accumulations and trap volume and can have a significant influence on reservoir performance during production. Furthermore, the prospective of structural or combination traps in stacked clastic reservoir settings that are typically found in many of the known hydrocarbon provinces in the Cuu Long basin, often critically hinges on the presence of a working fault side seal. Based on a thorough understanding of the key controls on fault seal risk and retention capacity, a consistent methodology to access these factors across a prospect portfolio is essential to achieve a balanced prospect ranking and an accurate assessment of prospect success volumes.

In the process workflow built by PVEP Blocks 01/97&02/97, the assessment of fault seal capacity and compartmentalization in the Oligocene reservoir have been incorperated by using fault deformation, displacement,

juxtaposition, fault zone thickness, shale gouge ratio (SGR), shale smear factor (SSF), clay smear potential (CSP), fault thickness and permeability.

Studied results showed that the Sperrevik et al. (2002) method provides the best historical match. In contrast, the Manzocchi et al. (1999) method does not account for diagenesis, it predicts low sealing potential for the faults and has the poorest historical match. In addition, the Jolley et al. (2007) method takes diagenesis into account and has a better history match, but the predicted permeability is still too open.

Key words: *3D fault seal capacity, fault clay, fault thickness, fault permeability, fault transmissibility.*

Electric Submersible Pump application for oil production in naturally fractured granitic basement reservoir

Nguyen Phuc Khai [a], Nguyen Pham An Khuong [a], Luong Thi Thanh Huyen [a], Tran Ha Minh [a]

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Abstract

In fields with increasing water cut and depleting reservoir energy, Electric Submersible Pump (ESP) installation is a sustainable production option. It helps to extend life of the wells by lower abandonment pressure and therefore increases the recovery factor. In addition, the gas lift saving from ESP conversion wells could be utilized to optimize others wells' productivity thus boosting the total field production.

Over the last 9 years, Cuu Long JOC has been conducted 5 ESP campaigns in fractured granitic basement reservoirs which bringing full of surprises. The selected field for ESP pilot was brought on production initially in 2008 with over 75,000 bopd. However, water breakthrough occurred after 8 months quickly reduced the total field production to 5,000 bopd in 2013. At the time of ESP conversion, gas lift has already optimized and it is not sufficient to maintain the rate as most of wells flowed with 95% water cut. With ESP application, the wells were able to reach 12,000 blpd and reduce the water cut not only for itself but also for adjacent wells. Despite the pump average run life is not meet the expectation, ESP application shows better efficiency in term of oil production compared to gas lift under the same reservoir conditions.

This paper summarizes a process of ESP application in high temperature environment including candidate selection, ESP design and actual production performance. The learning and experience developed from 11 ESPs installation provide an insight about the potential of ESP use for oil production in fractured basement reservoir.

Key words: *Electric Submersible Pump (ESP), high water cut, basement reservoir, artificial lift*

Some applications of Scanning Electron Microscope to the study of fractured reservoir rock

Trinh The Luc [a], Pham Van Tuan [a], Bui Hoang Bac [a], Nguyen Huu Hiep [a], Le Thi Duyen [a]

[a] *Hanoi University of Mining and Geology, Hanoi, Vietnam*

Abstract

Scanning electron microscopy (SEM) is a powerful tool for visualising reservoir pore and grain framework systems which (SEM) provides qualitative information about pore geometry through direct observation of a rock or a pore cast of the rock. This aids in understanding reservoir productivity capabilities. The SEM is useful for locating and identifying minerals, particularly clay minerals -an aid when designing drilling and completion programs. Scanning electron microscopy, unlike conventional light microscopy, produces images by recording various signals resulting from interactions of an electron beam with the sample as it is scanned in a raster pattern across the sample surface. Combined with backscatter detector (BSE), energy dispersal X-ray spectroscopy (EDS), EDS – Mapping. SEM can yield multiple types of information about geological samples at the same time, such as superficial microstructure, BSE image, component analysis, and crystal structure features. In addition, new technich of SEM like Qemscan and FIB (Focused ion beam) can automatic minerals mapping and approach to 3-D imaging.

In this paper, we use granite rock from granitic basement reservoir, Bach Ho Oilfield as examples to discuss the geological application of SEM. The most important reservoir properties of granite rock in the oilfield are porosity and fractured pores that are abundant. The fractures have various sizes from mm to micro in width. Some large cracks have 1 - 3 cm in long and 100 – 600 μm in width. The small ones have 0.001 – 0.2 mm in length and 10 – 100 μm in width. Some large fractures were porefilled by crystals which have blade shape.

Key words: *SEM; SEM - EDS; reservoir; BSE; EDS - Mapping*

Submarine landslide and associated polygonal faults development: a case study from offshore Norway

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Abstract

Submarine slide and polygonal faults have been investigated using high-resolution 3D seismic data, over an area of 2300 km^2. The study area is located on the continental slope, offshore Norway. Submarine sliding covers more than half of the study area, and is part of the Storage slide. The slide developed a series of extensional faults at the upper extensional zone which is gradually changed to chaos seismic facies, interpreted as mass transport deposits. There is no clear evidence of compression/contractional zone downslope. Polygonal faults are highly developed in the KS1 and KS2 interval, corresponding to the Lower Miocene age. The fault has small offset of c. 10 – 30 ms TWT, spacing ranges between c. 500 m and 1 km. Within this faulted interval, faults tend to develop intensively below the submarine sliding and much less out of that area.

Bright amplitude anomalies are observed within the north south – elongated anticline structure. It has been mapped over an area of c. 135 km^2 coinciding with the top anticline. Among those, there are two obvious negatives, bright amplitude reflectors which are relatively flat at 2670 ms TWT (flat spot 1) and 2800 ms TWT (flat spot 2). These flat spots are interpreted as hydrocarbon-brine contacts. Flat spot 2 is bounded by the structure contour but there is no evidence for the unconformable with the lithologic reflections from the trap boundary, thus this still needs to be confirmed by well data. Bright amplitude anomalies suggest the existence of hydrocarbon in the trap, in addition, the occurrence of polygonal faults is linked to seal potential covering the underneath petroleum reservoir, proving the great hydrocarbon potential in this area.

Key words: *Polygonal faults, Submarine landslide, Bright spot, Norway.*

Controls of normal diagenesis on poroperm parameters in red beds: examples in Miocene Muddy Creek Formation, Mesquite basin, USA and upper Devonian Old Red Sandstone, Orcadian basin, Scotland

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Abstract

General diagenetic patterns in Miocene Muddy Creek Formation and upper Devonian Old Red Sandstone (ORS) can be characterized as following: i) early diagenesis characterized by the formation of early hematite, carbonate and clay cements; ii) burial diagenesis followed by the formation of quartz and feldspar overgrowths, poikilotopic calcite and pore-filling clays; iii) late diagenesis characterized by the formation of late hematite replacing previous poikilotopic carbonate cements.

Normal diagenesis has a significant impact on poroperm parameters as indicated by the destruction of pore spaces from cementation and intergranular pressure solution. Early cementation in unburied sandstones of the Muddy Creek Formation reduces sample porosities to 2 – 20% of the total rock volume. Cementation destroyed the original porosity of studied sandstones through pore occlusion due to the formation of equant and meniscus calcite cements. Point-count data indicate that the intergranular cements of studied samples range between 22 and 44%; in contrast, the intergranular porosities range from 2 to 20% of the total rock volume. These consequently indicate that the interganular volumes that are considered to represent the original porosities of studied samples, ranged from 35 to 50% of the total rock volume.

Completely pore-occluding poikilotopic calcite cements in the upper Old Red Sanstone reduces poroperm values to as low as 5% porosity and 0.003 mD permeability. Late reddening is caused by replacive hematite cement in the calcite. In addition, normal diagenesis also has an impact on porosity enhancement due to dissolution in the studied red beds. This improves porosity and permeability by as much as 14% and 254 mD in the upper ORS.

Key words: *Normal diagenesis, Old Red Sandstone, Mesquite basin, Orcadian basin.*

Diagenesis and the effects of cataclastic deformation on the Permo-Triassic New Red Sandstone, Isle of Arran, Scotland

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Abstract

Diagenesis in the Permo-Triassic New Red Sandstone, Isle of Arran is characterized by early cementation of hematite, clay, and calcite minerals, followed by burial compaction, quartz, feldspar, and pyrite cementation. Cataclasis post-dated the quartz and feldspar cementation and reduced the grain and pore aperture size in deformed samples. Samples with cataclastic bands typically have 18% porosity and 8.81 mD permeability on average. Whereas, undeformed samples have an average porosity of 22% and an average permeability of 381 mD. Cataclasis was not as important as diagenesis in controlling sandstone porosity and permeability. However, cataclasis resulted in lower porosity and very poor to medium permeability in deformed samples. Cataclastic bands compartmentalize reservoir sands and cause a high heterogeneity in undeformed porous sandstones.

Poikilotopic and blocky calcite cement postdates early clay and hematite cement. In addition, burial quartz and feldspar overgrowths also postdate the early clay and hematite. However, the poikilotopic calcite fills in framework grains that have larger void volumes than the grain/grain contacts where quartz overgrowths are present. Cataclasis resulted in fracturing of quartz and feldspar overgrowths. Therefore, the cataclasis occurred after the development of quartz and feldspar cementation. Dissolution postdated the formation of authigenic feldspar and pyrite formation resulted from hematite reduction. The distributions of grain and pore sizes against cumulative mercury volumes in studied samples shows a high level of reduction of grain and pore aperture sizes for deformed samples from single-cataclastic and multi-cataclastic bands. The distribution of apex volumes illustrates that the effective mercury porosity of the multi-cataclastic band sample may be reduced up to > 2 times in comparison to undeformed samples. However, the sample of a thin single cataclastic band has only a slightly lower apex volume in comparison to the host sample.

Key words: *New Red Sandstone, diagenesis, cataclasis, defoformation.*

Deep geological structure of An Chau trough base on new study data

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Abstract

An Chau trough with an area of about 10,000 km2 located in the Northeast of Vietnam is the southwest tail of the Mesozoic Thap Van Dai Son basin and has a complex geological structure. The geological structure of An Chau trough has been studied since the 70s of the last century, however, previous studies were mainly surface geological studies. Deep structure studies only based on measurement gravity data at the scale of 1/200.000 with outdated machinery, equipment and processing technology. With the goal of re-searching, investigating and surveying oil and gas resources, from 2013 to 2017, Vietnam National Oil and Gas Group has deployed measuring over 9,000 km of the Airbone high-resolution Mag-Gravity survey with the resolution of measuring points on the measure-line from 6m to 7m/point, more than 450 ground gravimetric points and acquiring over 1,000 km 2D seismic survey. All magnetic-gravity and seismic data collected in the field is then processed at processing centers with modern technology such as Sander Geophysics - Canada, Institute of Geophysics - VAST, CGG Veritas Singapore. The results of interpretation and integration of these new documents together with the previous geological documents have initially allowed to identify and construct a deep geological model of An Chau trough. The results of this study will help clarify the history of geological development of the study area based on evidences that can only be observed on seismic data. In addition, these results also help to make orientation for explorating mineral resources in general and oil and gas resources in particular.

Key words: *An Chau trough; deep structure; Mag-Gravity interprtation; Seismic interpretation; Oil and Gas*

Diagenesis including cataclastic band development in the Permian Penrith Sandstone, Vale of Eden Basin, England

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Abstract

Diagenesis in the Penrith Sandstone is characterized by early hematite and mixed illite/smectite cementation, followed by burial compaction, feldspar and two episodes of quartz cementation. The primary quartz overgrowths are characterized by heterogenerous luminescence; however, the secondary quartz overgrowths are characterized by thinner and darker luminescence. Cataclasis post-dates primary quartz cementation, and significantly reduces grain and pore aperture size. The apex of mercury volume for a deformed sample was reduced up to three times in comparison with the undeformed rock. Dissolution occurred during cataclasis as authigenic hematite was removed in deformation zones, improving pore aperture size and consequently enhancing sandstone porosity and permeability. Recent fracturing created fractured pores and improved porosity and permeability in tight cataclastic samples. Evidence for syn-cataclastic dissolution is observed in the samples studied. This is indicated by the dissolution of authigenic feldspars and the enhancement of poroperm parameters adjacent to cataclastic zones and the absence of hematite cement within them. Based on those the sequence of diagenetic evolution in the Penrith Sandstone can be reconstructed.

Host samples were characterized by good to very good poroperm values, varying between 20 and 24% porosity and from 809 to 1445 mD permeability. Cataclastic core plugs have 13 - 21% porosity and 0.12 - 39 mD permeability. The porosity reduction by cataclasis was estimated to be as much as 4.5% on average. Fracturing and dissolution improved poroperm parameters in studied samples.

Recently fractured core plugs have about 292 mD permeability on average. Dissolution-cataclastic samples have 32% porosity and 18 mD permeability, whereas dissolution-host samples have 31% porosity and maximum permeability as much as 2469 mD on average. Cataclasis occurred in combination with in situ significant reservoir dissolution and fracturing may improve the reservoir quality in excellent parameters.

Key words: Diagenesis, cataclasis, dilation band, Penrith Sandstone, Vale of Eden Basin.

Assessment of the height of hydrocarbon column in stacked, laminated, thin-bed hydrocarbon bearing reservoirs: a case study in Te Giac Trang, Cuu Long Basin

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Abstract

The Te Giac Trang (TGT) field is a very special hydrocarbon accumulation in the Cuu Long Basin with the oil-bearing intervals are typically thin-beded, laminated sands. The stacked oil shaly sands are interbeded as layer cakes, multi oil water contacts, good oil storage, good permeability reservoir, high heterogeneity of reservoir, complex geological features, the discontinuous hydrocarbon bearing reservoirs separated into difference oil pools by tectonic faults. The hydrocarbon bearing sands are distributed along the structural axis in the Northeast-Southwest direction, creating a significant challenge in reserve estimations for the initial oil in place, in designing development wells and selecting the location of the development drilling wells along with perforation strategy. The low-risk determination of the height of hydrocarbon column above free water levels of each reservoir has played an important contribution in the field development plan.

Application of oil column height shows that the bottom of perforated intervals must be at least 5m above the oil-water contact to avoid early break through. In addition, the blank between perforated intervals must be at least 3m. This is in case of early break through, mechanical water shut-off or casing patches can be applied. It is necessary to make a balanced level between perforation intervals to avoid cross-flows during production shut in. The reservoirs with the same hydrodynamic regime or the same depth of oil-water contact, oil properties and reservoir characteristics are allowed to be produced in mixture at the same time.

Key words: Te Giac Trang Field, oil water contact, hydrocarbon column, development well location.

Prospect inventory and commercial evaluation to support the decision of exploration well: a case study in P prospect, Block Y, Nam Con Son Basin, Vietnam

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Abstract

This paper is to describe a case study of technical and commercial evaluation to support making decision for exploration well. The P prospect is marginal and located in existing petroleum developed area. The main steps of evaluation workflow are: i) calculate hydrocarbon volume; ii) define geological risk elements and estimate consolidated risk and average hydrocarbon volume; iii) make decision tree analysis to support the investment decision. The original prospect and zone are renamed. The Hydrocarbon Initially In Place was estimated by the volumetric method using Monte Carlo simulation for both Gas and Oil cases for both zone A and zone B.

The geological risk was accessed for each zone. Of those, zone B has a higher chance of success than zone A, as Pg(B)=33% and Pg(A)=29%. The dependence risk of zone A and B is 80% and independence risks of zone A and B are 36% and 41% respectively. The combined chance of success and hydrocarbon volume for two zones were conducted to find the chance of success and mean hydrocarbon volume for project. In this case, chance of success is 62% and failure is 38%; the mean recoverable reserves is 9.4 Bcm of gas or 11.7 MMcm of oil.

The decision tree was established to combine technical and commercial evaluation. The chance to find gas is 43.4% with mean gas volume is 9.4 Bcm; therefore, risked gas volume is 4.1 Bcm. The chance to find oil is 18.6% with mean oil volume is 11.6 MMcm; therefore, risked oil volume is 2.2 MMcm. Expected Monetary Value was accounted as much as 573 MMUSD for all cases including gas discovery, oil discovery or dry well as commercial failure.

Key words: prospect inventory, marginal prospect, geological risk, prospect commercial evaluation.

Estimation of Heat Flow Using a Bottom Simulating Reflection Based on 3D Seismic, Kribi-Campo Basin, West Africa

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Abstract

A Bottom Simulating Reflection (BSR), interpreted to mark the base of the Gas Hydrate Stability Zone (GHSZ), has been identified using 3D seismic data from the Cameroon continental slope margin. The BSR covers an area of c. 350 km2 in water depths ranging between 940 m to 1750 m across an area characterized by high- and low-gradient slopes, gullies, scours and fans. The thickness of the GHSZ is ~100 – 250 m, assuming an average velocity of 1800 m/s. Pockmarks are intensively developed across the slope and most of them are observed in the BSR area (90%). The theoretical temperature and pressure condition for the gas hydrate stability zone provides an opportunity to estimate the temperature at the BSR and then geothermal gradients and heat flow. The estimate is based on hydrate stability conditions for pure methane – seawater system, hydrostatic pressure model and a range of P-wave velocity models for the GHSZ (ranging from 1600 – 1800 to 2000 – 2200 m/s). Local measured seafloor temperature varies from 4.1 ^{o}C to 6.6 ^{o}C. Geothermal gradient was calculated showing the range and distribution of thermal gradients in the BSR area from 0.046 ^{o}C/m to 0.094 ^{o}C/m (with an assumed velocity of 1800 m/s). Thermal gradient anomalies have been observed in association with gullies, vertically stacked channels and in some individual pockmarks. The highest anomalies (0.08 ^{o}C/m – 0.094 ^{o}C/m) are found in the depression areas of pockmark trains, within seafloor gullies. These positive anomalies are most likely controlled by active or recently active fluid advection and expulsion through the Cameroon slope.

Key words: Gas hydrate; Bottom Simulating Reflection (BSR); Geothermal Gradient; Cameroon margin.

New discoveries in Oligocene and significances on petroleum exploration in northern Song Hong basin

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Abstract

The study area is located in the northern part of Song Hong basin, having complicated geological structure and depositional environment. Intensified exploration activity during the last decade in the area has been proved to have high hydrocarbon potential by many discoveries in the fractured carbonate basement and Miocene inverted trends. The first gas discovery was recently found in the Oligocene sandstones with good gas and condensate flow which is a significant achievement in hydrocarbon exploration of the area.

Oligocene sediment was deposited in fluvio-lacustrine environments and widely distributed in grabens/half-grabens which was formed during the rifting phase relating to strike-slip Song Hong shear zones. The tectonic inversion in late Oligocene has created series of inverted structures favorable for hydrocarbon migrating from Eocene (?) – Oligocene source rocks to be trapped. This significant gas discovery confirmed huge hydrocarbon potential of the Oligocene formation that need further exploration in north of Song Hong basin.

Key words: *discoveries in Oligocene, northern Song Hong basin.*