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# GEO 2010 Abstracts Part II

The following abstracts are a selection from those accepted for presentation at GEO 2010, the Ninth Middle East Geosciences Exhibition and Conference that was held in Bahrain on March 7–10, 2010. GEO 2010 was organized by Arabian Exhibition Management (AEM), the American Association of Petroleum Geologists (AAPG) in collaboration with the European Association of Geoscientists and Engineers (EAGE), and was supported by the Society of Exploration Geophysicists (SEG), Dhahran Geoscience Society (DGS), Bahrain Geoscience Society (BGS), Geological Society of Oman (GSO) and Emirates Society of Geoscience (ESG).

The abstracts that are published here by permission of the organizers represent the second group that primarily cover the characterization of Middle East reservoirs. The abstracts have been slightly edited and/or reworded so as to conform to a more common style and format; for example, capitalization of formal names for formations, geological periods and stages, etc. Some abstracts required rewording to clarify the scientific content or were submitted as short papers. Every effort was made to present these as concisely and accurately as possible. GeoArabia sent the pre-press version of all the abstracts to the primary authors for their approval, but regrettably some could not be reached or did not respond.

In the next issues of GeoArabia, additional groups of GEO 2010 abstracts will be published so that a permanent record of these important studies is available to GeoArabia's readers and the international geoscience community.

## 681063 Seismic characterization for stochastic modeling of fractures in the Jurassic Najmah and Sargelu reservoirs of Umm Gudair Field, West Kuwait

*J.A. Abdul, S. Matar, P. Convert, D. Rocher and V. de Groen*

In the context of oil recovery optimization in naturally fractured carbonate reservoirs of West Kuwait, fracture detection along with lithological distinction offers a great added value as it helps in characterizing the wells' productivity. This presentation describes a seismic workflow for characterizing reservoirs affected by fracture corridors as well as small-scale diffuse fractures. The method is based on the parallel use of two approaches: (1) seismic attributes analysis performed on post-stack data, and (2) lithology prediction using pre-stack inversion and characterization. A multi-variate attribute classification technique is applied to generate zonation maps that highlight sub-seismic fractured corridors. Statistical cluster analysis is used to identify the seismic classes, and then to group traces having the same characteristics. At the end of the process, the interpretation highlights discontinuous zones affected by large-scale fractures. Ranking of so-called "fractured seismic facies" in terms of probability of fracture occurrence allows generating an index map for the large-scale fracture (swarms/corridors). The 3-D stochastic fracture model eventually incorporates this large-scale fracture prediction.

Modeling of sub-seismic scale fractures can also be guided by seismic data. Higher fracture density is, in this reservoir, related to cleaner limestone units. Hence, lithological discrimination based on pre-stack attributes (P and S impedances) was performed to predict the lithological changes impacting on fracture density. This method associates shaliness at wells with impedance variations. Based on (Ip,Is) crossplots, discrimination between limestones and shales was made possible in 3-D at the seismic scale. Volumes and derived maps of shale occurrence were generated to provide guidelines for the simulation of shaly rock-types in the geological model. This 3-D facies model was then used to model the network of small-scale factures. From this workflow, two types of deliverables based on seismic data and calibrated at wells provide robust guidelines for 3-D stochastic fracture model building within the whole Umm Gudair Field area.

## 680492 Application of 3-D seismic multi-attribute and neural network technique for reservoir prediction: A case study for the Marrat Formation, Kuwait

*M.H. Abdul Razak*

The use of 3-D seismic attributes for predicting reservoir properties away from the wellbore has been routinely used in the industry. Recently a study utilizing multi-attribute analysis and a neural network technique applied to one of the Marrat reservoirs in west Kuwait has not only described the reservoir geometry but has also opened up new areas for exploration. Furthermore, the seismically derived porosity volume has also been integrated with the geological model for future well placement.

The Middle Marrat limestone reservoir of Jurassic age in the Dharif Field is one of the major oil producers in the area. This field, discovered in 1988, is an elongated NE-trending anticline, with a major fault to the west. The reservoir thickness varies from 50–230 ft and porosity from 12–20%. Since a pilot water injection program is being initiated, a good reservoir description would be essential for planning a successful injection program. The porosity volume derived from neural network analysis of the seismic data has been a key in identifying inter-well areas as well as regions away from the wells with good porosity, and is consistent with the available geological information. Incorporating the porosity volume as a "soft constraint" to the available geological model has further refined the model and is expected to assist in effective placement of future wells.

## 726095 Integrated reservoir analysis and geochemistry leads to increasing production from underdeveloped reservoir in the Awali Field, Bahrain

*N.K. Abdulla, N. Nedham, C.R. Murty and Y. Al Ansari*

Since the Awali Field was discovered in 1932, the main focus of development was on major formations of the field, leaving shallow formations not fully exploited. Today with the increase in oil price and the depletion of major formations, there is a greater need to consider increasing production from these underdeveloped zones. This case study describes the measures applied with the purpose of increasing production from the Magwa Zone, which is the most economically attractive of the shallow zones. The zone is the basal member of the Rumaila Formation of the middle Cretaceous Wasia Group. It is predominantly limestone with interbedded shale. An integrated methodology was adopted to enable a better understanding of the reservoir production behavior and to explain the lateral heterogeneity of the formation. This investigation was triggered by the variation in the formation's water salinity from north to south. Water-saturation maps, rock type, production history, geochemistry and structure were used as the main inputs in this analysis. The interpretation of trends between these factors was used to explain the behavior of the reservoir. The outcome of such investigations is of critical value in determining the location of new development wells, selecting candidate wells for recompletion and planning for enhanced oil recovery (EOR) processes. This presentation explains how a better understanding of the reservoir through data integration has resulted in a significant increase in oil production.

## 680412 Prediction of reservoir heterogeneity and quality: Examples and lessons from outcrop analogs from Wajid Sandstone, Saudi Arabia

*O.M. Abdullatif, M. Makkawi and M. Mahgoub*

This study seeks to characterize the reservoir rock heterogeneity and quality using sedimentological, statistical and geostatistical approaches. Paleozoic fluvial and shallow-marine reservoir analogs from the Wajid Sandstone at outcrop in southwest Saudi Arabia are the target for this study. The impact of depositional and post-depositional processes on porosity and permeability distribution were investigated at macro- to micro-scale. The study revealed a wide range of facies, environments, textural and compositional variations at outcrop scale. The porosity and permeability distribution show variability and complex patterns most probably reflecting different scales of depositional and diagenetic influences. The complex relations among parameters may be attributed to variable interrelationships. At the macro to meso-scale these include the meter-scale stratigraphic hierarchy, depositional cyclicity and lateral and vertical facies changes. While at micro-scale petrographic features, such as grain size, sorting, matrix and cement content and type all seem to be influential. The geostatistical porosity and permeability models show some agreement and differences which can also be attributed to the aforementioned controlling factors.

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## 680415 Reservoir porosity and permeability prediction from petrographic data using artificial neural network: A case study from Saudi Arabia

*O.M. Abdullatif and M. Sitouah*

Understanding reservoir heterogeneity is essential for the assessment and the prediction of reservoir properties and quality. This study investigates the prediction of the reservoir petrophysical properties of the Ordovician Upper Dibsiyah Member of the Wajid Sandstone in southwest Saudi Arabia. The artificial neural networks (ANNS) technique was used to study pattern recognition and correlation among the petrographic thin section data such as grain size, sorting, matrix and cementation percentages, and petrophysical properties of the reservoir such as porosity, permeability and lithofacies. For this purpose, artificial intelligence techniques were designed and developed and these are the multilayer perception (MLP) and the general regression neural network (GRNN). The good agreement between core data and predicted values by neural networks demonstrated a successful implementation and validation of the network's ability to map a complex non-linear relationship between petrographic data, permeability and porosity. The GRNN technique provides better prediction of the reservoir properties than that obtained from the use of the MLP technique.

## 705069 Enhancement of simulation models using petrophysical facies

*M.S. AbouSayed*

If you ask a group of geoscientists and engineers "What is facies?" you will definitely get very different answers. The strange thing, amusingly, is that they are working for long periods of time, at the same office, on modeling the same reservoir within the same field. Additionally, both groups are exchanging a lot of data and most of these data are facies data (type, properties, category, etc.). The wrong definition of facies negatively affects not only on the definition of the reservoir geometry but also on the population of the reservoir properties. Geoscientists define facies from the geological point of view based mainly on the lithology, depositional environment, diagenetic history, fossil content and other geological criteria. Based on these parameters geoscientists subdivide the facies into lithofacies, biofacies, microfacies, icnofacies, electrofacies and seismic facies. Engineers look at the facies as a different group of rocks that have different flow regimes. Hence, if the flow of fluids within a body of the reservoir is consistent this can be considered as one facies. Both definitions need to be fine-tuned to get the best results out of our reservoir models.

This presentation suggests starting by using the petrophysical facies where the reservoir modeler uses all basic petrophysical reservoir rock properties (porosity, permeability, wettability, capillary pressure and relative permeability) to differentiate between the different geological bodies within the reservoir rock. This way we use the factors that control the fluid flow in a rock as a basis for differentiating different geological settings. That will definitely give us a better chance to define the geometry of each facies and then help us populate its properties within the defined reservoir bodies. Out of 21 modeling projects in the Middle East and North Africa region, 16 did not obtain the anticipated history matching because of the wrong definition of facies. Several case studies including both carbonate and sandstone reservoirs showed a much better history matching after correcting the definition of facies.

## 680569 Movable oil identification and viscosity estimation in Lower Fars heavy-oil reservoir: A case study

*K. Ahmed, M.A. Rampurwala and G.S. Padhy*

Reservoir fluid typing is one of the key parameters in well completion and field development planning. While the resistivity and nuclear logs provide basic information about fluid type, detailed but non-continuous fluid profiling is obtained from down-hole pressure-volume-temperature (PVT) sampling. The recent advancement in nuclear magnetic resonance (NMR) logging helps immensely for the continuous fluid identification.

The Lower Fars Formation in Kuwait is a shallow unconsolidated sandstone reservoir containing heavy oil. The oil viscosity in the field varies from tens to thousands of centipoises both vertically and laterally. In-place PVT-quality fluid sampling with wireline formation testers in this low-pressure reservoir is quite challenging and time consuming. The deployment of advanced NMR logging technique was successful in identifying movable oil and providing a continuous oil viscosity profile.

The presence of clay within heavy-oil sand affects fluid identification as the clay-bound water and heavy-oil NMR signals overlay and occur at fast relaxation domain. The standard diffusion method has poor resolution at early T2 domain and interpretation suffers from the effect of restricted diffusion. The advanced NMR logging tool provides measurement at multiple radial depths and the diffusion measurement is found useful in identifying movable oil in such environments. An integrated approach combining advanced NMR log with the nuclear and resistivity logs is used to identify mov-able oil and fluid-type variation and to estimate a continuous oil viscosity profile. NMR station measurements helped to enhance signal to noise ratio to increase confidence in log interpretation. The viscosity profile estimated using this approach correlates quite well with the PVT sample analysis available in the field. The next logical step is the optimization of workflow to produce consistent and more quantitative viscosity results, which may require lab NMR measurement of Lower Fars oil samples and core calibration.

## 724492 Reservoir optimization and monitoring challenges in the Nahr Umr reservoirs of the Awali Field, Bahrain

*J. Al Bahraini, A.A. Shaban and A.E. AL-Muftah*

The Nahr Umr Formation in Awali Field contains three reservoirs that vary from calcareous siltstones to sandstones. They are the second major producing zones in the field. They are separated by an 8–10 ft thick shale bed from the overlying Mauddud limestone reservoir. All these reservoirs have been producing since early 1930s and the Mauddud reservoir has been under gas injection since 1938. These reservoirs have diverse fluid contents and different hydro-dynamic systems that are in communication through the extensive faulting.

For such mature reservoirs with a long production history, identifying by-passed oil, underperforming areas, inter-communicating areas, locating infill wells and upgrading the reserves are challenging tasks. This presentation describes the application of a practical process: (1) development of a systematic workflow for production optimization and reservoir analysis; (2) identifying and highlighting reservoir trends, patterns and anomalies; (3) locating the underperforming wells and areas, and recommending solutions; and (4) identifying essential patterns for consideration in the overall development plan. The challenge was to evaluate large datasets in a short time and cost-effective manner.

The technique uses a streamlined workflow of reservoir assessment processes. After the data is gathered and formatted it is validated using several processes associated with both static and dynamic models of the reservoir. Quick interpretations of these models generate opportunity regions, re-completion candidates, and new infill potential in the reservoir. Based on the processes run in the Nahr Umr zones it was possible to understand the reservoir performance and main issues associated with field development. Utilizing these techniques, the recently completed development-drilling program resulted in an efficient reservoir management process aimed at decreasing the decline rate and increasing the recovery.

## 678398 The usefulness of light hydrocarbons in classifying Oman oils

*M.R. Al Ghammari and P.N. Taylor*

In order to improve the understanding of the origin of light oils, which have low biomarker concentrations, Petroleum Development Oman (PDO) developed a new classification tool based on the distribution of light hydrocarbons (LHC). This tool proved useful for identifying mixing patterns between light oil/condensate and normal medium and low gravity oils. The database for this study consists of 71 non-biodegraded normal oil/condensate samples from various oil families and sub-oil families of Oman. All oils/condensates were first classified using C15+ compositions. Various plots and parameters based on light hydrocarbons composition (LHC) were collected from the literature and used in this study. It is found that the published LHC parameters are very useful tools in classifying Oman oils (e.g. Schaefer parameters, Halpern correlation parameters). In addition to the published parameters, principal component analysis was performed on these samples using the C7 composition (22DMP through to Toluene). Two useful parameters were successfully extracted from the statistical evaluation that can distinguish between various oil families. These are total DMCPs/n-C7 and (22DMP+24DMP+11DMCP)/ECP.

Most of the LHC parameters were able to distinguish between four oil families; Huqf, Athel, Q and Mesozoic (Natih+Tuwaiq) oil families. Each oil family is characterised by a unique LHC distribution. Huqf oils are generally characterised by higher paraffins and lower cycloalkanes than the rest of the oil families. Q oils are characterised by higher branched alkanes than the rest of the oil families. Mesozoic oils (Natih+Tuwaiq) are characterised by higher cycloalkanes than Huqf and Q oils. Apparently, most of the Natih oils have Tuwaiq input and no single oil sample has been found for pure Natih oil. Therefore, most of the plots cluster them together. However, one parameter 22DMP+24DMP+11DMCP/ECP was found to be able to tentatively distinguish between the two oils, Tuwaiq pure oils and Natih/Tuwaiq mixed oils. Both Natih and Tuwaiq oils are characterised by higher cycloalkanes than Huqf and Q oils. Only one sample of apparently pure Silurian 'Safiq' oil was available for C7 composition. The composition of this oil was different from the published characteristics of Silurian oils elsewhere in Arabia. We are not able to determine whether our single oil sample is representative for Silurian oils in Oman.

## 731168 Comprehensive history matching a complex carbonate reservoir in Maydan Mahzam Field, offshore Qatar

*A. Al-Ahmed, V. Fryer, M. Javed, A. Al-Abdulmalik, P. Léandri, J. Chautu, R. Bohbote, M. Inizan and C. Fraisse*

The Maydan Mahzam Field in offshore Qatar is a complex carbonate oil reservoir of the Late Jurassic Arab Formation. It was brought on production in 1965, with a short period of natural depletion before starting water injection through dump-flooders located on the flanks of the reservoir. An integrated study has been launched by Qatar Petroleum in order to optimize the future development of the field and maximize the recovery of the remaining oil-in-place. In this context the understanding of the main producing mechanisms of the past forty years is of major value. This requires reservoir modeling with extensive and detailed history matching. This presentation discusses the comprehensive methodology used to obtain a detailed and reliable history match of the Maydan Mahzam Field. A high quality 3-D reservoir model has been generated to properly represent the underlying geological concepts describing this multi-layer carbonate reservoir. Moreover, the reservoir presents a complex structural history, with a large number of faults of high throw, generating possible communications between the 4 main layers of the reservoir.

To achieve history matching the pressure response of the model was first analyzed and compared to the existing measured data, in order to qualify the pressure balance between the different regions of the model (crestal part *versus* flooded flanks, faulted blocks). At the same time, the sweep efficiency of the dump-flooders as well as the aquifer was investigated for a better understanding of the production mechanisms involved in each part of the field. The main parameters affecting the model and its response compared to real production data were identified. Their possible range was determined based on existing field data or analogs, in order to ensure the reliability of the final history match. To explore the possible combinations of these parameters in a systematic and efficient way, experimental design techniques were used, enabling quantification of the impact of each parameter on the model results, thus significantly enhancing the history match process. At this stage, a well by well analysis was carried out in order to correctly reproduce the water displacement within the reservoir at a detailed scale. Finally, a comprehensive history match of the Maydan Mahzam reservoir was obtained: pressure history, water breakthrough and water cut history are reproduced in most of the 120 oil producers of the field. Also, the sweep efficiency within the reservoir is better understood. Based on this history matched model, reliable predictions can be made to optimize the production of the remaining reserves, and evaluate the feasibility of using enhanced recovery techniques on the field.

## 731172 Use of pre-stack seismic data to guide the 3-D rock-type distribution of the Arab-D in Maydan Mahzam high-resolution geological model

*A. Al-Emadi, S. Robinson, N. Jedaan, N. Desgoutte, M. Blum, G. Lecante, B. Caline and C. Fraisse*

Maydan Mahzam is a carbonate field located offshore Qatar with principal oil production from the Arab-D reservoir. In order to optimize the management of this mature field, Qatar Petroleum undertook a comprehensive reservoir modeling exercise using an up-to-date integrated multi-disciplinary approach, combining reservoir, geological, geophysical and production data. This presentation illustrates how seismic data was used to quantitatively constrain the reservoir model between wells. The main objective of the seismic reservoir characterization part of the project is to retrieve a robust distribution of reservoir properties between wells from pre-stack seismic data. This will provide a better control of uncertainties in petrophysical property distribution (namely porosity and dominant lithology probability) away from the wells.

As a first step, a comprehensive geophysical well database was generated in parallel to the rock-typing phase of the project in order to maximize the consistency between reservoir rock-type definition and upscaled reservoir properties which can be predicted or discriminated from seismic data. In practice, this also means that elastic parameters (compressional and shear velocities and impedances) were linked with the rock-type definition schemes. Pre-stack inversion was performed to produce optimized P and S impedance volumes. The combination of inversion results with the previous petro-elastic analysis defined the training database to be used for dominant lithology discrimination and porosity prediction. Supervised discriminant analysis was used to discriminate dominant dolomite from dominant limestone (i.e. at seismic scale) and associated probability of occurrence. As a second stage, lithology-dependant porosity *versus* impedance relationship was calibrated at wells.

As a result, volumes of probability of occurrence of dolomite and porosity volumes were used to derive an average dolomite occurrence probability map for Arab-D interval DI and average PIGE (to be put in full) maps for Arab-D intervals DII, DIIIA and DIIIB. These average maps were generated using surfaces of the high-resolution geological model converted back to time, to ensure the topological consistency between the constraints extracted from seismic data and the geological model.

## 699675 Detection of fractures with dual oil base mud imager in Jurassic carbonate reservoirs, North Kuwait: A case study

*A. Al-Enezi, H. Al-Ammar, B. Khan, H. Abu-Hebail, A. Al-Ajmi, M. Qidwai, A.A. Aviantara and M. Al-Khabbaz*

The Najmah, Sargelu and Marrat formations of Mid to Late Jurassic age are the prime targets for hydrocarbon exploration in North Kuwait. These carbonate reservoirs, particularly the Najmah and Sargelu, are generally tight. Despite low matrix permeabilities, the presence of natural open fractures in these reservoirs is believed to have enhanced the permeability by several fold, as is evidenced by production rates as high as tens of millions of standard cubic feet of gas and several thousand barrels of condensate/oil per day. As such, proper evaluation of fractures is key to exploration and exploitation of these tight carbonate reservoirs. The image log is one of the key tools used for fracture characterization in the Jurassic reservoirs. In contrast, the oil base mud imager (OBMI), which is the tool used for resistivity imaging, has the disadvantage of limited borehole coverage. This limitation was successfully overcome by using dual OBMI in one of the recent wells. The aim of this presentation is to demonstrate the innovative technique in dual OBMI tool and to highlight its advantages over the conventional OBMI tool even with two passes. In dual OBMI, two OBMI tools are stacked one over another at an angle of 45 degrees. Thus there are 8 pads in dual OBMI as compared to 4 pads in conventional OBMI tool. Each pad acquires five measurements and the data is displayed as a color image oriented with respect to the geometry of the tool and borehole. With dual OBMI the borehole coverage area is increased by 100%. In an 8 inch borehole the coverage with conventional OBMI is 32%, whereas, it increases to 64% with dual OBMI. Increased borehole coverage allows more complex features, both large and small, to be properly identified and described. Structural and stratigraphic features as small as 1 cm can be seen, yielding a wealth of high-resolution azimuthal information. This results in enhanced interpretation of the borehole and of the regional geology. It has applications for structural and stratigraphic analysis and high-resolution net-pay count. The following fracture types were determined using dual OBMI: (1) open or closed fractures; (2) resistive fractures; (3) continuous or discontinuous fractures; and (4) possible fractures. Dual OBMI also saves rig time as it obviates the practice of two passes with conventional OBMI to increase the borehole coverage. This technique not only provides double borehole coverage with higher resolution but also saves valuable rig time.

## 727508 Controls from formation of early replacement dolomites and diagenetic anhydrite: Reactive transport modeling of dynamic interactions between geothermal and reflux circulation

*A.B. Al-Helal, F. Whitaker and Y. Xiao*

Geothermal heating and brine reflux have been invoked to explain early dolomitization of platform carbonates. Reactive transport modeling (RTM) suggests that geothermal convection can form a wedge-shaped dolomite body thickest at the platform margin, while reflux can form a tabular body which thins away from the brine source. In natural systems flow will respond to both drives and vary through time with changes in platform top conditions, for example as brine pools develop and disappear, and this is likely to significantly impact both dolomitization and associated anhydrite precipitation. A model technique (TOUGHREACT) is used to investigate the dynamic interactions of geothermal convection and brine reflux. Reflux of brines (85‰) rapidly restricts geothermal convection to the platform margin where only minor dolomitization occurs. Brines infiltrate to

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considerable depth, but fluid flux is most rapid at shallow depth due to reducing permeability with depth, permeability anisotropy, and diagenetic modification of permeability. Simulations suggest complete dolomitization to 150–200 m depth within 1 My beneath the brine source.

Reflux dolomitization may enhance reservoir quality at shallow depth where associated anhydrite precipitation occludes porosity beneath the main dolomite body. The predicted anhydrite volume is almost twice that suggested by earlier simulations that do not incorporate heat transport. Increasing geothermal heat flux has little effect on geothermal circulation, but does accelerate reflux diagenesis. Cooling the platform top from 40 to 25°C slows reactions and displaces the anhydrite zone downwards so it may become completely decoupled from the brine source.

When brine-generating conditions cease, subsurface brines will continue to flow and have been suggested as a drive for continued dolomitization (a variant termed "latent reflux"). Our simulations demonstrate that latent reflux does not form a significant amount of dolomite due to prior $Mg^{2+}$ consumption at shallow depth, although as geothermal circulation becomes re-established, platform margin dolomitization rates increase. RTM offers considerable potential for improving our understanding of diagenetic reactions and their impact on reservoir quality in such hybrid flow systems. However, the veracity and utility of predictions depend on the specification of meaningful boundary and initial conditions, and the temperature regime appears to play a critical role in the dolomitization and anhydritization story.

## 681966 3-D geological modeling in Saudi Aramco: Current practices and field examples

*M.A. Al-Khalifa, A. Al-Gaoud and N.F. Najjar*

Current practices of advanced 3-D geological modeling will be discussed and selected field examples will be presented, where advanced 3-D geological modeling technology was utilized. They include object-based modeling, seismic data integration, fracture modeling, and engineering dynamic data integration. 3-D geological modeling is the science of creating 3-D numerical representation of the subsurface and quantitatively predicting reservoir properties. It plays a vital role in the modern oil and gas industry with applications that span a wide spectrum, ranging from well planning and reserves assessment to reservoir simulation and future production predictions. Input data for geological models come from direct information such as measurements of reservoir rock and fluid properties, and indirect information such as interpretations and conceptual models. It is very challenging to integrate geological, geophysical, petrophysical, and engineering data that are recorded at different scales, both vertically and horizontally, from small-scale core measurements to medium-scale log data to large-scale seismic interpretations.

At Saudi Aramco, 3-D geological models are actively used by reservoir geologists for horizontal and high-slant well placement and geosteering. The models are frequently updated as new data and interpretations from newly drilled wells become available. In addition, reservoir engineers use geological models in their simulation studies to predict the flow and behavior of oil, gas, and water in the reservoir to optimize production. Knowledge learned from fluid-flow simulation is integrated back into the static model to improve the distribution of reservoir properties. This iterative loop between geological modeling and dynamic-flow simulation is essential to generating the most accurate static and dynamic models.

## 680495 Geophysical monitoring of steam flood in Omani heavy oil field

*F.A. Al-Kindi, M. Burreson and D. Enns*

Occidental is conducting a geophysical monitoring program to aid optimization of production from a heavy oil field in Central Oman. The Permian age Gharif reservoir consists of three stacked sandstone units spread over a gross interval of about 50 meters with average porosities of 30%. Oil recovery is stimulated by steam injection into each of the three reservoirs to lower oil viscosity. Steam injection and production alter reservoir properties such as temperature, pressure and saturation. A 4-D modeling study was carried out to investigate the impact of these reservoir changes on compressibility and rigidity of the rocks. Synthetic seismic models were derived from our understanding of the reservoir rock properties combined with the history-matched reservoir models. The modeling predicts a change in the reservoir interval velocities of approximately 10–15%, resulting in a change in acoustic impedance that should be large enough to observe in surface seismic data.

Modeling also suggests that changes in the reservoir properties will be localized close to the steam injectors and that these anomalies could be strong enough to identify in surface seismic without time-lapse differencing. A crosswell tomography survey was acquired through a well that injects steam into all three reservoirs. The crosswell survey confirms a reduction in reservoir interval velocity by 10% associated with the steam injection. Comparison of the crosswell tomography cross section with the equivalent predicted velocity section from the reservoir simulation highlights differences between the reservoir simulation prediction and how steam is actually affecting the reservoir. Petrophysical and production surveillance data have helped our understanding of these differences. The crosswell tomography helped in assessing the connectivity vertically between the three reservoirs and horizontally between the study wells as the resolution is higher in the crosswell than in the surface seismic. The crosswell tomography and modeled seismic response also serve to calibrate the surface seismic response which is needed to highlight field-wide lateral reservoir changes. Information gained from geophysical monitoring that is correlated with observation and production data is important for monitoring steam movement in the subsurface and optimizing field production.

## 681005 Elastic moduli sensitivity to reservoir pore fluids

*M.G. Al-Otaibi*

Detailed seismic modeling work has been carried out to identify the most appropriate elastic rock modulus (or moduli) that are sensitive to reservoir pore fluid types. This work is being applied to both oil and gas bearing clastic and carbonate reservoirs from different fields within Saudi Arabia. The sensitivity of each modulus to the reservoir pore fluid saturation was also analyzed. Among those moduli are Vp/Vs ratio, Lambda-Rho, and bulk modulus. Modeling results ranked investigated elastic moduli with regards to their effectiveness as "fluid indicators". These results also set rules of thumb as to which modulus is suitable for a given set of reservoir conditions.

## 694158 Carbonate reservoir rock typing: An integrated case study

*H. Al-Sahn, A. Mayer, I. Al-Ali, H. Al-Housani and F. El-Wazeer*

Reservoir rock typing is a process by which the reservoir is abstracted into discrete units characterized by certain static properties and dynamic behavior. The challenges of this process are to find the correspondence between rock fabrics with their diagenetic alterations and their petrophysical properties, then to distribute these discrete entities in the reservoir. This presentation shows a case study completed for a major complex carbonate reservoir onshore Abu Dhabi. The study includes three main elements. The first is a detailed facies analysis based on the description of available cores. The second element is a detailed petrographic analysis where diagenetic overprints were described using 3,000 thin sections. The third element is a petrophysical data grouping using static and dynamic properties.

The main challenge was to establish a systematic relationship between the three elements (facies, diagenesis and petrophysical groups) because, apart from diagenetic modifications, similar carbonate facies deposited under similar conditions would exhibit different petrophysical properties due to other factors (e.g. compaction, micrite content and dominant grain types). The study established a manageable number of reservoir rock types with distinct capillary pressure properties applied to the cored wells. For non-cored wells, an artificial neural network back-propagation algorithm was applied to estimate permeability. We achieved permeability prediction with more than 90% correlation coefficient and then used it with log porosity to assign petrophysical groups using calibrated mercury injection capillary pressure (MICP) driven Winland's R35 cutoffs. The workflow followed and the techniques applied are presented.

## 680604 Fracture characterization and modeling of unconventional Najmah-Sargelu reservoirs of Umm Gudair Field, West Kuwait

*A. Al-Shamali, D. Ray, N. Verma, S. Matar, V. Groen, G. Joussineau and W. Al-Khamees*

The Najmah-Sargelu unconventional naturally fractured carbonate reservoirs are spread across many fields in West Kuwait, some of which, such as Umm Gudair are on production for the last 25 years. Natural fractures have a significant impact on the reservoir performance as they affect well productivity. Therefore, understanding their significance through fracture characterization is helpful in well placement and field development. This presentation shows an overview of the efforts to build a 3-D stochastic fracture model for reservoir characterization in the Umm Gudair Field. The model is generated in FracaFlow©

through the analysis and integration of well data like cores (including oriented core), borehole images (BHI), well-logs, mud losses, production logging and well test data along with 3-D Q-Seismic data through structural, seismic attribute and seismic facies analyses.

The impact of lithology on fracture occurrence was quantified based on rock-typing and distributed using a high-resolution, sequence-stratigraphic framework. Rock types are a real 3-D fracture driver and provide a reliable means of adjusting the density of diffuse fracture in the Najmah-Sargelu reservoirs of Umm Gudair Field. Three sets of diffuse fractures were identified from borehole image data: N20°E, EW and N170°E. Large-scale fracture corridors including sub-seismic faults, identified from seismic analysis were calibrated with core and BHI fractures through fracture data analysis workflows. The model finally incorporates two scales of tectonic fractures: diffuse fractures and large-scale fractures that have a direct bearing on well and field production behavior. The fracture calibration was performed using the dynamic data set such as production log and well wise production data. Synthetic well tests were simulated and matched with the real build-up data at wells. These data were then used to propagate 3-D fracture properties (fracture porosity, fracture permeability and equivalent block size) for constructing a reservoir simulation model.

## 683824 Reservoir characterization contributions to develop Khurais complex, the largest increment in Saudi Arabia: A story of success

*K.I. Al-Sheddi, R.G. Hart, M.X. Mat Yaacob, M.X. Sher-Afzal and R.G. Demaree*

The Khurais complex is located in the central part of the Kingdom of Saudi Arabia, about 250 km southwest of Dhahran and 80 km to the east of Riyadh. It consists of three main fields: Khurais, Abu Jifan and Mazalij. Khurais Field is the largest among these fields, approximately 90 km long and between 5 and 18 km wide. This is the second largest onshore oil field in the Kingdom preceded by Ghawar Field. It was discovered in 1957, while Mazalij and Abu Jifan were discovered in 1972 and 1973, respectively. One of the key aspects of the Khurais complex development plan is the proper selection of well locations. This presents three major challenges from the perspective of reservoir characterization, namely: the subsurface structure, reservoir quality and fluid contacts. New geophysical data recently acquired made a significant impact in defining the structural geometry and depth uncertainties required for well placement, and in identifying the fractured areas, which are most probable within the field's boundaries. Full-fold 3-D seismic data was integrated and interpreted over the entire complex to assist in this process.

Recent reservoir characterization studies have focused on defining reservoir quality variation in core data, well log data, seismic data, image log analysis, facies mapping, gravity data and magnetic data. The product of these studies is a new fully-integrated conceptual model that contains facies distributions, reservoir quality indices, fracture analysis, structural analysis, detailed stratigraphic correlations and hydrodynamic information. Reservoir characterization provided technical operations support during the development of this increment on a 24/7 basis spanning two years in time. A large number of wells were planned and maintained in multiple databases and more than 300 wells were geosteered and monitored with thousands of feet of reservoir contact.

## 682898 Real-time petrophysical integration of NMRWD, FPWD and LWD triple-combo in slim holes

*Y.M. Al-Shobaili, D. Seifert, R. Akkurt and S. Dossari*

Real-time petrophysical analysis in slim-hole wells is complicated by the presence of heavy-oil and tar zones and the availability of the slim logging tools. The reservoirs in this case study contain heavy oil and tar in the flanks, and accurate knowledge of viscosity trends becomes essential for the placement of water injectors. The "tar mats" create a permeability barrier between the water and desired oil. Optimal pressure support and oil recovery from water injection into these reservoirs requires the well trajectory be kept as deep as possible in the producible oil column while at the same time, not encountering the heavy oil or tar mat.

The geometry of these heavy-oil and tar deposits has been mapped with previously drilled vertical wells that act as control points. These wells indicate that the tar mat is neither flat nor uniform in thickness. Additionally, the well data show an increase in the oil viscosity with depth from the field oil to the tar mat. Injectors need to be placed in the injectable zone close to the heavy-oil/tar boundary to have good pressure support and obtain desired injection rates and sweep efficiency.

Recent developments and innovations in 4¾ inch logging while drilling (LWD) technology are allowing for the better placement of wells. The development of formation pressure while drilling (FPWD) measurements has shown that formation pressure pretest information can be used to identify unintentional penetration of the impermeable zone. The more recent introduction of a slim-hole nuclear magnetic resonance while drilling (NMRWD) tool and the development of an in-house methodology, allow for the characterization of the hydrocarbon components and prediction of the hydrocarbon viscosity. The petrophysical integration of real-time formation pressure tests, mobility and viscosity information along with NMR fluid characterization are being used to optimally place and steer wells, to minimize contact with the immoveable hydrocarbon, and to improve well injection performance and oil recovery.

## 725373 Estimation of barrel of oil equivalent of gas using PVT multi-stage separation data

*M. AlBahar, A. Bora and B.B. Singh*

Over the last sixty years, Kuwait's gas production has been mainly coming from associated gas sources from its large and thick reservoirs undergoing natural depletion. Recent discoveries of deep Jurassic gas have considerably changed the overall relative make-up of the gas stream. The current gas stream includes gas production from existing oil reservoirs, deep gas reservoirs, condensate, and volatile oil reservoirs. As a result of this, the gas stream is becoming richer. However, in the past there has been no systematic attempt to understand and estimate the barrel of oil-equivalent (BOE) of overall gas based on the relative contribution from the reservoirs in Kuwait. This study is a first attempt to develop a new methodology and process to estimate the BOE factor for Kuwait taking into account all the major oil and gas producing reservoirs in Kuwait.

The study considered all gas composition information including PVT test data on all PVT samples for more than 200 wells and gas outlet points. It focused on the gas compositional behavior and the amount of energy associated with different sources of gas. The study shows that any oil company must develop and adopt its own BOE factor for reporting the gas volumes in terms of oil equivalent. Key technical contributions of this work include: data evaluation techniques, estimation of calorific values and conversion of the calorific value to BOE factor (per well, reservoir, field and company), and general correlations of gas and fluid properties for quick projection of BOE value.

## 678057 Gas log monitoring - Challenges and uncertainties in gas injection pilot in carbonate reservoir: A case study in United Arab Emirates

*M. Amin, O. Al Jeelani and H. Al Mansouri*

The field under study is a Lower Cretaceous anticline carbonate reservoir in onshore Abu Dhabi, UAE. It is characterized by well-developed porosity but low to moderate permeability, with occasional, high-permeability streaks. The field structure is highly faulted. Many reservoir layers are juxtaposed due to faulting which has a significant role in the reservoir's performance. Pressure maintenance is supported by peripheral water injection. Two gas injection pilot projects are underway to investigate the benefits of gas injection above minimum miscibility pressure (MMP) in the low permeability reservoirs. As part of the field development a peripheral water injection scheme is in place, and two gas injection pilots were commissioned for injection in the entire reservoir. The purpose of this work is to: (1) present an overview on the implemented strategy for log monitoring in sense of the logging types, logging timing and the interpretation techniques; (2) summarize specific actions taken to gather log data; (3) discuss and evaluate the field observations; and (4) address the challenges and uncertainties of the monitoring process. The results of the monitoring observations in this work are being incorporated into simulation studies for a conclusive assessment of the pilots.

## 743105 Evaluating fundamental controls from depositional facies heterogeneity in a carbonate ramp using forward stratigraphic modeling

*M.S. Andres, P.M. Harris and G.D. Jones*

Much of our understanding of the depositional facies heterogeneity, to date, derives from geological concepts, outcrop studies and subsurface information. Deposited strata represent the unique solution to a combination of fundamental controls at the time, not including subsequent diagenetic, tectonic and/or burial overprint. Forward stratigraphic modeling (FSM), in contrast, provides an opportunity to simulate multiple solutions by isolating one of the fundamental controls. In this capacity we use the FSM tool 'Dionisos' to investigate the role of various input parameters and their control on a grain-dominated carbonate ramp setting typical of the Middle

East. Specifically, we focused on the extent and distribution of reservoir and non-reservoir facies as they are key to understanding and predicting reservoir connectivity and potential performance in carbonate ramps.

Our base-case model comprised several fourth-order sea-level fluctuations, variable subsidence, carbonate production (ooids, peloids, carbonate mud), and shale parameters. Transgressive surfaces, often mud-dominated, are an important element in ramp systems as their up-dip extent and thickness offer potential for compartmentalization and flow barriers. Hence, we simulated system tracts comprising a mud-dominated initial early transgression, and a middle-late transgression characterized by the onset of ooid production peaking in the early highstand.

Sensitivity analysis focused on varying ooid production rates and their production as a function of water depth. In the latter, extending the depth production profile (from 5 to 7 to 9 m) impacted volume (tripled at 9 m) and extent of the ooid facies (i.e. 8 km of increased progradation). Likewise, the shape profile, straight *versus* gradual decline to zero production, impacted clinoform thickness and basin-ward extent as accommodation space is filled. In such cases the ensuing sequence encountered a greater modeling window resulting in subsequent thicker sequences and faster progradation. By setting sediment erosion and low-energy transport rates to zero we evaluated the amount of in-place production *versus* transport. Our simulations suggest that down-dip transport and erosion are key elements but underappreciated in understanding reservoir-prone facies connectivity.

## 705154 Quantitative seismic attributes for fractured reservoir characterisation

*E. Angerer and S.M. Hahighi*

It is a considerable challenge to effectively produce from heterogeneous fractured reservoirs in a complex structural setting. In this Middle Eastern onshore field the production mainly comes from fractured igneous intrusive and metamorphic basement rocks and an overlying clastic formation. This partially eroded and therefore heterogeneously distributed clastic formation can also have significant fracturing. The presence of this clastic formation has a big impact on production of the drilled wells but unfortunately it is below seismic resolution and therefore cannot be conventionally mapped by seismic. The aim of this study was to detect fractured zones and to describe the distribution of the clastic formation using seismic attributes calibrated to well information. A 400 sq km, high-fold, wide-azimuth seismic data set was acquired to provide an optimum illumination of the complex reservoir structure. Azimuthal anisotropy from the wide-azimuth seismic survey proves to be one of the main productivity indicators in this reservoir. Well production is quantitatively correlated with anisotropy intensity. In some wells additional matrix porosity contributing to production is present in the heterogeneous sandstone layer above the basement. The partially eroded sandstone layer can be detected with seismic inversion. Therefore we find that a combination of these seismic attributes provides a powerful tool to describe this complex reservoir. The attributes are used for well planning and reservoir modelling.

## 706203 Integrated reservoir characterization in unconventional, low-permeability carbonate reservoir, Abu Dhabi, United Arab Emirates

*A.A. Ardill, T. Al-Maskari, A. Al-Shehhi, A. Benamara, C. Smart and K.A. Al Daghar*

As the era of "easy" oil draws to a close, the energy sector is shifting focus towards previously overlooked, unconventional, "challenged" reservoirs. Unconventional reservoirs will play a vital role in filling the void as existing, conventional assets move into maturity and irreversible decline. In Abu Dhabi, low-permeability carbonate reservoirs contain enormous volumes of hydrocarbon resource with substantial potential to replace a large wedge of the current production stream lost to standard reservoir decline. Reservoir characterization in these assets is a challenge as key static and dynamic information can be difficult to collect and difficult to interpret using traditional stand-alone methods. The key to robust reservoir characterization relies on the integration and reconciliation of various forms of static and dynamic data. A comprehensive, mid-appraisal characterization of reservoir quality, vertical communication and lateral compartmentalization of a multi-billion barrel asset in Abu Dhabi was completed using seismic, wireline, core, pressure, fluid property and capillary pressure information. This presentation will focus on the methodology and results of this study and illustrate the gains in basic reservoir understanding, the identification of critical information gaps to be filled prior to generating a robust full-field development plan for this reservoir, and how these identified gaps are used to drive future appraisal efforts.

## 695488 Organic geochemistry of crude oils and probable source and reservoir rocks of Marun oil field, southwest Iran

*E. Asadi Mehmandosti, S.A. Bowden, B. Alizadeh and M. Adabi*

Marun Field is located in Dezful Embayment area of the Zagros Mountains in Iran. It is one of Iran's largest oil fields and the geochemistry of its oil is discussed in this study. The dataset consists of: (1) 43 cutting samples from six wells; (2) 23 rock samples extracted from Cretaceous – Tertiary source and reservoir formations (Garau, Gadvan, Dariyan, Kazhdumi, Sarvak, Gurpi and Pabdeh formations); and (3) six crude oils from Bangestan and Khami reservoirs. The samples were studied using organic geochemistry and biomarker analysis.

Hopane and sterane biomarker parameters did not help constrain a single formation present in this region as the source rock for the studied oils. This may be because of the high thermal maturity of the oils relative to those of previous studies, which used extended hopane and sterane abundances for correlation purposes. Unfortunately hopane and sterane biomarker correlation-parameters for oils from the Bangestan and Khami formations have stronger statistical correlations with thermal maturity parameters than with other source indicators. Therefore aromatic biomarkers, which were less affected by thermal alteration were used. Ratios of methylated triaromatic steroids to triaromatic steroids, and the occurrence of alykylated-trimethyl-benzenes (derivatives of isorenieratene), suggest that the Kazhdumi Formation (often proposed as the most regionally important source rock) does not share biomarker characteristics with oil in the Bangestan and Khami reservoirs. Another notable feature is that the reservoir oil has distinctly lower thermal maturity values than bitumen extracted from adjacent source rocks, indicating that the oil and source rock bitumen originate from different thermal events. In the Dariyan and Sarvak formations a high amount of asphaltene occurs, but there is no evidence for biodegradation. Taken these aspects together with the occurrence of tar mats implies a complex filling history involving the mixing of different oil phases. Such a complex history may also explain the poor match of reservoir oils to a single adjacent source rock. The Marun oil field can be regarded as containing a complete petroleum system. It has a suitable cap rock, a carrier rock that allowed oil migration, as well as many mature source rocks that entered the oil window. But the oils currently present in the Bangestan and Khami reservoirs exhibit a lower thermal maturity and different biomarker characteristics to the region's most prolific regional source rock.

## 662035 Application of soft computing to lithology prediction: A case study from the Marun Field

*S. Asadullahpour and B. Habibnia*

This presentation focuses on predicting lithology, especially shale intervals. Shale is very significant in zonation, layering, formation damage and well logs. Neural clustering network (NCN), neural pattern-recognition network (NPRN), feed-forward back-propagation network (FBN), fuzzy clustering means (FCM) and adaptive neuro-fuzzy inference system (ANFIS) are used. They are tested on three wells in carbonate reservoirs of Marun Field and the results are discussed for Well-222 with 811 utilized data of raw log reading.

First, a two-step unsupervised clustering approach is performed. In each step the optimum number of clusters is selected by the NCN and clustering is performed by the FCM. The first step determines the major cluster that presents overall qualities of data in a more homogeneous manner. The second clustering finds lithology classes and is performed only on the major cluster. Analysis showed that the fourth FCM output cluster indicated shale intervals. Other clusters, each mostly included one of dolomite, limestone and sandstone, but not as distinguishing as shale. To expand the results from the major cluster to the whole data sets, we trained a FBN which demonstrated an accuracy of 94.82% in shale prediction. Final FCM outcomes could be turned into percentile form determining how much rock acts similar to shale. The unsupervised procedure could be modified to predict other lithology types by introducing different input logs. This procedure can be also used when various parameters of formations are to be optimally correlated, for example for reservoir zonation.

We then implemented supervised prediction by using core data. We first used NPRN which presented a validation precision of 98.8%. Then ANFIS was utilized with FIS generation methods of FCM and subtractive clustering. The FCM generation method acted as efficient as NPRN. Supervised prediction of other rocks can be conducted in the same way as shale.

Previous attempts mostly included supervised predictions (core data is necessary); however, we applied an unsupervised procedure and compared

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its results to the supervised predictions and shale intervals. Analysis of two other wells showed virtually the same precisions. The fact that the unsupervised procedure does not use any previous analysis or core data makes it best for formations which are not fully analyzed. It gives a precise formation evaluation in a few minutes. The final FBN could be solely utilized to predict lithology in other wells.

### 703210 Determination of surface relaxivity from NMR T2 measurements

*A. Ashkar, Q.J. Fisher and C.A. Grattoni*

Nuclear magnetic resonance (NMR) is a very useful tool to determine rock properties. The NMR responds to the hydrogen contained within rocks and can be related in a direct or indirect way to porosity, pore-size distribution, rock permeability, capillary pressure, wettability and water saturation. The magnitude of the T2 signal is used to obtain the matrix independent porosity. Bound and moveable water can be estimated using the relationship between response and saturation. Empirical relationships can be used to several petrophysical properties, however, more detailed information is needed on surface relaxivity.

To determine the effective surface relaxivity and establish a methodology, sandstones ranging from tight gas to poorly lithified sands were analyzed. The tests performed included conventional core analysis (porosity-permeability), back scattered image analysis (BSI), and NMR T2 relaxation on both fully saturated and drained conditions. The permeability of the samples ranges from 0.01 to 1000 mD and their porosities between 2 to 15%. The mean T2 of the brine saturated samples ranged from 0.8 to 400 ms. Arithmetic average of T2 cutoff (calculated as the point where Swi intercepts the T2 distribution) is 39.2 ms however values ranged between 1.45 ms and 242 ms where clay content played a key factor in reducing cutoff time. Back scattered images were used to establish the link between T2 relaxation and pore area. This relationship was then used to obtain the surface relaxivity.

This presentation shows an innovative methodology to calculate the effective surface relaxivity using the signal generated from mean T2 relaxation with the objective of obtaining a better understanding of the NMR capabilities in assessing in situ reservoir properties. The methodology combines pore volume from NMR and BSE image analysis. However, in the case that image data were not available a correlation has been generated, using a large number of samples, which can be used to obtain surface relaxivity only from NMR T2 data. The surface relaxivity and T2 distribution can then be used to determine formation capillarity and in consequence be able to model the saturation height function to provide an input to the geological static model. The advantage of this method comes from the direct use of actual data, while the number of samples analysed enables the final outcome to be generalised, and therefore suitable to be used as an empirical approach when experimental results are not available.

### 706311 Heterogeneity and reservoir quality of Yabus and Samaa formations, Agordeed Field, Melut Rift Basin, Sudan

*A.A. Badi, O. Ali, A. Farwa and O.M. Abdullatif*

The Tertiary Yabus and Samaa formations occur within the Melut Rift Basin of interior Sudan, which is regionally linked to the central and west African Rift System. The Yabus and Samaa formations in Agordeed Field are some of the most productive oil reservoirs in the Melut Basin. The reservoirs are composed of sandstone and mudstone lithofacies that differ in size and length along and across the basin. The reservoir sandstone, which occurs at shallow burial depth, was deposited within fluvial/lacustrine environments. This work aims to describe and characterize the reservoir heterogeneity and to investigate its impact on reservoir quality and architecture. This study employed a multidisciplinary and integrated approach that investigated and synthesized stratigraphic, sedimentological, core, log, petrographical, petrophysical and seismic data from Agordeed Field. The stratigraphic and lithofacies analysis indicated that the Yabus and Samaa formations systematically vary in their facies, sequences and stacking patterns within the basin. Reservoir heterogeneity exists at multiple scales, where the reservoir sandstones' macro- and micro scale heterogeneity shows vertical and lateral variations along and across the basin. These variations reflect the tectonic, depositional and post-depositional controls within the proximal to distal fluvial, prodelta and lacustrine environments. The porosity and permeability distributions are controlled by the heterogeneities within the formations, such as stratigraphic layering, facies, diagenetic processes, and fracturing. Porosity is enhanced by extensive fracturing and grain dissolution creating intergranular, intragranular and moldic porosity. In addition, permeability is also increased by fractures which connect separated buildups and directly affect the reservoir quality. Assessing the different scales of heterogeneity is important to understand their impact on reservoir quality and architecture in Agordeed Field.

## 704220 Understanding reservoir quality in Ara stringers (South Oman Salt Basin): Diagenetic relationships in space and time

*S. Becker, L. Reuning, P. Kukla, S. Abe, S. Li, J. Urai, S. Farqani and Z. Rawahi*

The Ediacaran – early Cambrian Ara Group of the South Oman Salt Basin consists of six carbonate to evaporite (rock salt, gypsum) sequences. These Ara Group carbonates are termed A0C to A6C from the bottom towards the top of the basin. Differential loading of locally 5 km thick Cambrian to Ordovician clastics onto the mobile rock salt of the Ara Group caused growth of several isolated salt diapirs, which resulted in strong fragmentation and faulting of the carbonate intervals into several isolated so-called 'stringers'. These carbonate 'stringers' represent a unique intra-salt petroleum system, which has been successfully explored in recent years. The goal of this study is twofold: (1) to detect trends in the spatial distribution of diagenetic phases within the stringers and their effect on reservoir properties; and (2) to unravel the relative timing of diagenetic phases and to link them to the burial history of the salt basin. Mineralogy, rock fabrics and geochemistry of ca. 200 samples from several petroleum wells from the late Neoproterozoic A2C interval were analyzed and combined with pre-existing data.

Our analysis demonstrates that permeability is to a large extent governed by dolomite crystal size. For a given porosity rock fabrics with larger crystal sizes show higher permeabilities. Crystal size is strongly controlled by depositional facies. Grainstone and boundstone facies show larger crystal sizes than mudstone to packstone facies. The crystal size distribution was determined for cored wells by thin-section analysis and estimated for uncored wells from borehole-image-log-derived lithofacies distribution. The combination of porosity and crystal size information from logging and core data allows calculation of field-scale permeability maps with high vertical and lateral resolution. These maps comprise crucial information for better prediction of reservoir quality in the analyzed fields, planning of new exploration wells and better volumetric calculations. An integration of the paragenetic sequence derived from thin-section analysis with results from finite element and discrete element models further helps to constrain the effect of salt tectonics on fracture formation and fluid evolution within the stringers.

## 681128 Understanding the pore pressure, burial history and rock properties using 3-D basin modeling

*A.G. Bhullar*

Three-dimensional modeling of the petroleum system offers the possibility of evaluating the pore pressure and filling history of tight gas reservoirs by integrating different processes involved in the evolution of sedimentary basins and corresponding pore fluids. This approach also provides the possibility of evaluating the rock properties combined with the depositional history of the basin, which ensures a more geologically coherent process. Conventional pore-pressure prediction workflows such as seismic velocity analysis, petrophysical methods and real-time monitoring of drilling operations have their limitations in this data constrained setting and play. In many of these areas with deep and tight reservoirs, poor seismic and quality calibration data, complicate the pore-pressure prediction. The data from these methods is further limited by their static nature, whereas basin modeling provides a dynamic approach. In this study, 3-D basin modeling results were presented from the South Ghawar area of the Arabian Basin where pore pressure evolution combined with the filling history and rock properties of reservoirs was investigated. In addition, the effective stress and porosity trends were modeled through time to understand the controls on reservoir deliverability.

## 680832 Pore network modeling: A route to improved reservoir quality assessment in Arabian reservoirs

*I. Billing, C.P. van Dijk and M. Touati*

Frequently in reservoir quality assessment, it is that which is not easily seen which has the biggest impact on fluid-flow behavior. The work presented here looks at the problems of quantifying two very different reservoirs, the carbonates of the Jurassic Arab-D Reservoir and the clastics of the Devonian Jauf Formation, both of which are impacted by pore system attributes beyond the resolution of a standard optical microscope. We highlight the results of the 3-D pore network modeling on these samples, contrasting this with the conventional approach to porosity and permeability calculation.

Studies of the Arab-D reservoirs in Saudi Arabia highlight the importance of microporosity as a significant factor affecting porosity-permeability transforms. Generally, such pores are less than 10 microns in size, but can account for over 50% of the

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pore volume in a sample. The more microporosity, the greater is the deviation away from the average porosity-permeability trend. Modeling of the pore network in clastics of the Jauf Formation is complicated by the texture and mineralogy of the sandstones. The grains are often covered with a thin layer of illite, comprising flakes which are oriented radially to the grain surface. High microporosity within this layer and the thin nature of the flakes results in a diffuse layer around each grain, lowering the permeability.

If we wish to model and predict permeability by transforming porosity data (such as obtained from wireline logs), then it is imperative to know the amount of microporosity. Given the problems of optically imaging microporosity in carbonates and sandstones, coupled with the complexities of a three-dimensional pore system, a 3-D modeling tool was used to capture and model these samples. Thin sections and scanning electron microscope images from the samples were studied statistically in 2-D and then the characteristics of the grains were reproduced in 3-D replicating the depositional mode of the grains, their compaction and diagenesis. An algorithm for pore network extraction then built a topologically-equivalent network consisting of balls representing the pore bodies and cylindrical segments representing pore throats. Porosity and permeabilities were obtained by calculating the proportion of voids space and by applying a pore flow code using elementary mechanisms of pore filling. Additionally, the Lattice Boltzmann Method has also been used to calculate pore flow inside the 3-D image itself.

## 670136 Sweet success in sour Arab reservoirs: How successful coring improved data integration

*A. Briner, A. Azzouni, C. Taberner and B. Wignall*

The South Rub' al-Khali Company Ltd. (SRAK) is an Incorporated Joint Venture between Shell and Saudi Aramco and is engaged in exploring for non-associated gas and liquids in parts of the South Rub' al-Khali Basin. The licence area contains significant quantities of ultra-sour gas in the Jurassic Arab Formation reservoir. Acquiring accurate subsurface data forms a key objective for SRAK in its currently ongoing exploration drilling campaign in the remote and challenging environment of the South Rub' al-Khali desert. SRAK's fourth exploration well targeted the Palaeozoic Khuff Formation but also gathered new data from the Mesozoic ultra-sour Arab Formation, where Saudi Aramco previously discovered hydrocarbon-bearing reservoirs in the late 1960s.

Over 350 ft of continuous core over the Arab Formation was cut to address the reservoir characteristics and determine the rock types, whilst downhole fluid samples and well-test data confirmed the fluid compositions. This presentation will focus on the extensive technical and operational planning and strategy that eventually led to a safe and successful coring job. It will also demonstrate how the results of the detailed and extensively planned and executed routine and special core analysis programme resulted in better interpretation of well-test data. We will also demonstrate how the detailed rock typing was used to construct new field models to update SRAK's view of the Arab Formation hydrocarbon resource.

## 702903 Geologic controls from pore pressure variation in the Najmah and Sargelu formations: A case study from Raudhatain Field, North Kuwait

*B. Chakrabarti, M. Al-Wadi, H. Abu-hebail, T. Al-Adwani, H. Al-Ammar, M. Al-Dkheel and J. Dasht*

The Najmah and Sargelu formations have a complex petroleum system due to high pressure (17 to 15 ppg), low formation porosity and variable fracture porosity. Pore pressure is extremely variable and difficult to predict. A geological study was done in Raudhatain Field to understand pore-pressure variation. Real time pore pressure, well logs, cores and image log fractures were used for the study. Fracture intensity logs from image log fracture data were generated. Correlations were prepared by integrating these data and well test result. Structure contour, isochore and pressure maps were prepared. Structure maps at all stratigraphic levels show uniform trends. Open-fracture intensity is high in the structural high areas in the Lower Najmah Limestone and Sargelu Formation and strike parallel to the regional trend. Away from the structural high area, open-fracture intensity is moderate with strike parallel to the regional trend. Pore pressure maps at the top of these two intervals show maximum pressure at structural high areas and uniform pressure gradient for the rest of the area. Isochore maps at the top of these two intervals show unidirectional depositional trends and maximum formation thickness at the structural high. Wells tested in the Lower Najmah Limestone and Sargelu Formation produced oil.

Open-fracture intensity in the Upper Najmah Limestone and Najmah Shale is low and limited to structural highs and its strike direction is inconsistent. Sharp contrast in pore pressure is observed between structural high and areas away from it. Isochore maps at the top of these two intervals show a shift in the depositional axis, and the maximum formation thickness is not always at structural highs. In the Upper Najmah Limestone and Najmah Shale limited fracture connectivity has resulted in more abrupt pressure variation. Maximum pore pressure is localised at structural highs due to the high concentration of open fractures. In the Sargelu and Lower Najmah Limestone high fracture intensity and consistent fracture strike have resulted in a more uniform pressure variation away from structural high. Open fractures parallel to the regional trend act as conduit for reservoir fluid migration and helped in transmitting formation pressure. Maximum formation thickness at structural high also resulted in an increase in effective reservoir thickness in Sargelu. The present study is a base work for building fracture network modeling.

## 680927 Integration of crosswell electromagnetic, geologic, production and seismic data for characterization, monitoring and dynamic modeling of water injection in a heterogeneous carbonate reservoir

*N. Clerc, S. El-Sembawy, S. Kumar, Y. Yin, L. Souche, S.L. Reeder, A. Alhoot, D.A. Lawrence and M. Gashut*

Crosswell electromagnetic (EM) tomography is a recently developed technique to map the interwell formation resistivity distribution. In this project, time-lapse crosswell EM surveys are used to monitor saturation changes in a water injection pilot in the basal low-reservoir quality units of a giant carbonate field in the Middle East. We demonstrate how EM results were used with seismic-derived structural information, geological data, structural models, time-lapse cased hole logs, pressure transient and production data to improve reservoir characterization and dynamic modeling. The evolution of water saturation is derived from measured resistivity distributions, which are obtained by inversion of the EM measurements with respect to an initial resistivity model. To obtain a detailed image of saturation changes, this model must incorporate realistic representations of the small-scale heterogeneities common to carbonate reservoirs. These include layer thickness variations and the presence of thin dense layers interbedded in some reservoir units. Such details allowed improvements in the quality and resolution of the EM results, leading to a better understanding of the reservoir architecture and the behavior of the water flooding process.

Preliminary simulation results using simplified models predicted high vertical sweep across the reservoir units, without encountering any flow barriers. This was inconsistent with the EM results, which show that the injected water stays confined within the lower reservoir units, and with the measured injection pressures and flow volumes, which were different from those predicted from simulation. Successive adjustments were therefore applied on the dynamic model to honor the EM and injection pressure results. Adjusting the permeability contrast across some layers prevents the upward movement of the injected water, and is consistent with geological interpretation of continuous stylolitic dense layers within the lower reservoir. In addition, fracture corridors, identified on seismic attributes and supported by PLT (production logging) data and field-wide review of borehole image logs, are used to account for the injected volume mismatch, yielding the correct injection pressure. When properly constrained with seismic, geological and production data the EM results provide important information on the location and behavior of the fluid front and identification of the required amount of geological detail that needs to be preserved in the dynamic model.

## 682078 Regional issues in Jurassic pore systems: Echinoderms, syntaxial overgrowth cements and a fifth porositon

*E.A. Clerke, D. Seedorf and Y. Mubarak*

Regional and well-established geological and diagenetic processes are re-examined in Jurassic carbonate reservoirs using the large amount of quantitative mercury injection capillary pressure (MICP) pore system data acquired by Saudi Aramco in the last eight years. An extensive Berri Field dataset included petrographic data and MICP pore system data obtained by Thomeer analysis. The Berri data from four Jurassic carbonate reservoirs is compared to other data, and specifically the Ghawar Rosetta Stone data using a regional depositional context. The anticipated increase of Jurassic carbonate-rim cement to the north of Ghawar is evident. Much more important from a pore system perspective are the amounts of syntaxial overgrowth cement and the correlative increase of echinoderms and foraminifera in the Hadriya and Fadhili. These latter increases necessitate a

fifth porositon (F-ESO), an additional maximum pore-throat diameter mode in the Hadriya and Fadhili pore system models, as compared to the four porositions that describe the pore systems of the Ghawar Arab D limestone and the Berri Arab and Hanifa reservoirs. Review of the Abqaiq Field petrographic and MICP data of Ross et al. (1995) provide independent support for the four porositons of Clerke et al. (2008) and also indicate the presence of a fifth (F-ESO) porositon in the Abqaiq Arab D.

The pore system effect of the predicted and present carbonate rim cements is imperceptible. Echinoderm and foraminifera are very abundant in the Berri Fadhili and show a steady decrease in abundance upward through the Berri Jurassic section, that is, the Fadhili, Hadriya, Hanifa and the Arab. Echinoderm abundance is closely linked to marine salinities and high magnesium calcite. Quantitative determinations of echinoderm and foraminifera abundance are shown to be correlative to and useful as a predictor of the pore destructive syntaxial overgrowth cement. Regional models of reservoir quality distribution could potentially be improved using maps of high precision Ca/Mg ratio relating to the high magnesium calcite of echinoderms and syntaxial overgrowth cements and maps of echinoderm abundances and habitats. These regional maps could relate broadly and inversely to reservoir quality and depositional salinity.

## 726631 Results of feasibility study of surface-to-borehole time-domain CSEM for water-oil fluid substitution in Ghawar Field, Saudi Arabia

*D. Colombo, S. Dasgupta, K.M. Strack and G. Yu*

Monitoring the advancement of flood from water injection in carbonate reservoirs is a major challenge for geophysical methods. Four-dimensional seismic has limited applicability to Middle East reservoirs with low gas-oil-ratio in carbonate rocks. On the other hand, electromagnetic (EM) methods hold the largest potential in such reservoirs due to the large resistivity contrast (over one order of magnitude) between oil-saturated and water-saturated reservoir rocks. Electromagnetic measurements, however, are noise sensitive thus special configurations need to be implemented to enable the detection of the extremely small variations of the electromagnetic field that are induced by oil being replaced by injection water. Controlled source EM transmitters on ground surface and borehole receivers represent the most effective layout configuration to improve the signal-to-noise ratio and to augment the aperture of investigation while addressing the signal-to-noise challenge through long recording times. Transient time-domain controlled-source EM techniques also provide broadband EM measurements and adapt to most geologic scenarios and to the conditions characterizing the Ghawar Field.

An advanced 3-D modeling study was carried out by considering reservoir geometry from 3-D seismic interpretation, anisotropic resistivity distribution from tri-axial resistivity logs (acquired from surface to reservoir depth in the monitoring well) and time snapshots of fluid saturations modeled in reservoir simulators. The study allows the determination of EM field sensitivity to fluid saturation changes in reservoir conditions. Results indicate the vertical component of the electric field (Ez) is the most sensitive parameter to fluid replacement for a survey layout consisting of surface galvanic transmitters radially distributed around the well and a single, multi-level, borehole receiver. Repeated EM modeling over different time snapshots evidence the possibility to effectively monitor in three dimensions the resistivity changes occurring in the reservoir as the water flood front advances. Estimates of the EM field strength allow quantitative evaluations of the noise floor required to detect the variations of the electromagnetic field. These estimates will be used in a successive phase of the study where actual noise measurements and noise cancellation techniques will be tested in the field.

## 667449 Fast appraisal and maturation of heterogeneous carbonate fields in a Shu'aiba stratigraphic play, North Oman

*A. Creusen, M. Carrera, L. Grant-Woolley, I. Mahruqi, M. Singh, M. Raghunathan, R. Spiteri and H. Soek*

We present two case studies discussing the synergy between appraisal and maturation activities of a heterogeneous carbonate play in North Oman. Key aspects are the effects of the complex geology on how quickly new fields can be brought on stream after discovery. The Upper Shu'aiba Formation was deposited as a series of prograding clinoforms on either side of the Bab Basin. The clinoforms comprise thick rudist build-ups, high-energy oolitic grainstone shoals and thin restricted miliolid oolitic grainstone sheets. They are around 800–

1,000 metres wide, over 10 kilometres long, 5–25 metres thick, and have high net-to-gross ratios. In both fields, the clinoforms are separated by non-permeable argillaceous facies forming stratigraphic traps below the Nahr Umr unconformity. The extent of the reservoirs, the distribution of good quality reservoir, the heterogeneity and impact of fractures remain as the key uncertainties.

Owing to low permeability of the facies, horizontal wells are preferred. Horizontal well placement in thick parts of the reservoir requires precise geosteering of injectors and producers in the top and base of the reservoir in order to maximize recovery. Well placement requires a balanced decision regarding the use of azimuthal geosteering tools in certain appraisal wells. Thinner units may require a more intensive azimuthal geosteering strategy as the heterogeneity of the shoals may lead to patchy reservoir quality and thickness, not detectable on seismic. In order to be able to make cost-effective decisions regarding facilities and drilling costs, the pattern design and geosteering strategy require an upfront decision on producer-injector spacing with enough flexiblity to deal with the heterogeneity encountered while drilling.

Water-flooding was selected as the optimal recovery mechanism and box-models were designed to simulate the physics of the process. Data acquired from routine core analysis, special core analyses, pressure-volume-temperature analyses, probe-based pressure measurements and vertical interference tests were utilized to build a simplistic dynamic model. Based on the results of these models, the optimal producer-injector spacing for varying thicknesses across the fields was determined. A maturation plan based on these well spacings was developed for each field. Well scheduling focused on maturation of the projects and volumes associated, mitigating appraisal and performance risks. The appraisal strategy includes drilling vertical pilot holes with horizontal sidetracks. Azimuthal geosteering technology was used to place the wells at desired distance to bed boundary.

## 680977 Drainage capillary pressure and resistivity index from short-wait porous plate experiments

*M. Dernaika, O. Wilson and S.M. Skjæveland*

Reliable experimental capillary pressure (Pc) and electrical properties (RI) as functions of saturation (Sw) history are essential as inputs for static and dynamic modeling of a reservoir. The only technique that simultaneously gives both Pc and Sw-RI relationship as functions of saturation history, and does not rely on a model with underlying assumptions for calculation, is the standard equilibrium method. This method is also known as the porous plate technique. The only disadvantage with this method is that it is time consuming caused by the low flux through the diaphragm (porous plate).

In this study we present drainage capillary pressure curves and resistivity index measured on reservoir rock samples by the standard equilibrium method at reservoir conditions. In parallel with this, a sister plug set has been analyzed by interrupting intermediate capillary displacement pressures before reaching equilibrium, with the objective of establishing Sw-RI relationship much faster. The results show that it is possible to establish identical Sw-RI relationship with a time-saving factor of three for the rock type under study.

Both data sets are analyzed with an extrapolation routine as an attempt to also predict capillary equilibrium for the fast plug set, that is, capillary drainage curve. Numerical interpretation of the experiments has been done as an attempt to investigate factors and optimized design of the interrupted capillary displacement pressure sequence for various porosity and permeability classes.

## 680533 Geological and near-surface geophysical data comparison helps integration of outcrop and subsurface data for fractured carbonate reservoirs description

*R. Di Cuia, D. Casabianca, A. Riva, E. Forte and M. Marian*

The heterogeneity of fractured carbonate reservoirs invariably controls their flow performance and economic value. Depositional facies, diagenesis and fractures, their distribution, spatial and genetic relationships are the sources of the heterogeneity of storage and flow properties within these reservoirs. Understanding such spatial and genetic relationships between sedimentary facies, diagenesis and fractures is fundamental to adequately describe fractured carbonate reservoirs, model their dynamic performance and identify the most appropriate development and management strategies. Particularly for fractured carbonates, outcrops are essential sources of information, in three-dimensions and at a wide range of scales, for making plausible and useful descriptions of the elements listed above. The challenge remains the effective use of outcrops in a subsurface modelling project where the co-located information are wellbore and seismic data. We aim to tackle this challenge starting from comparing the different information provided by direct geological observation and remote sensing and the different models resulting from using one or the other dataset in isolation.

We have selected a large quarry excavated within shallow water Cretaceous carbonates of the Apulian platform in the Italian Apennines foreland where the two datasets have been acquired. Geological (sedimentological, diagenetic, structural) data obtained from direct and detailed outcrop observations and measurements provide the means for building a detailed, geologically consistent 3-D model through interpolation between available 2-D exposures. Geophysical data consisting of a 3-D survey and 2-D lines acquired using ground-penetrating radar (GPR), provides more spatially continuous (albeit lower resolution and at times geologically inconsistent) geometric information. Comparison between the models resulting from the two different datasets highlights some important pitfalls related to scale, resolution, interpolation and extrapolation assumptions that modellers invariably have to make when building reservoir models with detrimental effects to the usefulness of these as prediction tools. This work provides insights on the modes of integrating outcrop and subsurface datasets for building fractured carbonate reservoirs models.

## 680520 Origin, distribution and petrophysical properties of high porosity/permeability sub-horizontal drains within a dolomitised sequence: Lessons learned from outcrop analogue

*R. Di Cuia, A. Riva, B. Caline and C. Pabian-Goyheneche*

Dolomite sequences and intervals often show the best reservoir potentials and are considered as key productive zones. It is difficult to completely unravel the diagenetic evolution of a carbonate sequence because of the complexity and variety of the processes that affect the rocks through their evolution. This is mainly due to the interactions between different processes and, in subsurface, because of the lack of complete datasets or the limited spatial representativity of well data. The origins and spatial variability of reservoir properties in structurally-controlled, partially dolomitised reservoirs are poorly understood because of their complexity. The use of outcrop analogues for better understanding subsurface reservoirs is essential to reduce some of the main reservoir uncertainties. The geometry, internal heterogeneity and petrophysical properties of dolomite bodies were studied in a Jurassic partially dolomitised outcrop analogue in the Southern Alps using an integrated, multidisciplinary approach. Dolomitisation of the lower part of the studied section led to the development of good petrophysical properties for a potential hydrocarbon reservoir, in particular by the formation of porosity systems interconnected with fracture and fault networks, hence assuring a consistent permeability through the entire sequence. The dolomitisation process determined a highly variable porosity network controlled by the original facies, the degree of dolomitisation and the structural framework. Near open fracture swarms or faults, the dolomitisation front tends to uprise, sometimes generating vertical chimneys that can cross the overlying sedimentary succession. In these zones the dolomite is massive, with a complete reworking of the original limestone, sometimes with strong evidence of hydro fracturing related to overpressured fluids. From these vertical dolomite bodies, high porosity and permeability bedding-parallel dolomitic bodies develop with lenticular or planar shape. These bodies can be 10's of meters in length and 1–3 meters in thickness and are often stacked one on top of the other along major fault zones. Based on core samples the porosity associated with these dolomitic bodies can be up to 25–30% with an extremely good connectivity. Matrix porosity and permeability, directly measured on plug analysis, vary respectively between 0.5–25% and 0.05–40 m Darcy. These petrophysical data appear strongly related to the diagenetic facies associations.

## 680732 Digital reservoir properties from cuttings: Case studies from tight gas sand and carbonate rocks

*E. Diaz, G. Li, B. Nur, J. Dvorkin and T. Zaleski*

Experimental quantification of rock properties requires regular-shaped intact fragments of rock. These fragments (plugs) are cut from cores extracted from wells. Coring is generally expensive and arguably impossible where new drilling technologies (e.g., coiled tubing) are employed. One application of Ingrain's technology was to quantify carbonate reservoir properties from drill cuttings that were collected from a deep deviated well. Naturally, the configuration of the well prevented the operator from extracting core material. As a result, digital rock physics lab was the only option to understand this reservoir and design production strategy.

A large number of these cuttings were imaged, segmented, and digitally tested at Ingrain. The resulting porosity, permeability, and elastic-wave velocity were consistent with the operator's expectation based on the well's performance. The latest-generation CT (computed tomography) scanners are used to capture in 3-D the actual fabric of reservoir rock samples - the pore-space and mineral matrix geometry and fabric - at resolutions as high as 100 nanometers. These physical measurements which require weeks or months in a physical lab can now be completed in a matter of days, on a massive scale and on any rock material, including sidewall plugs and drill cuttings. With the rapid advances in digital rock physics technology, we also envision that complicated natural pore-scale processes (fine particle migration, formation damage, diagenesis, and chemical reactions) will be virtually simulated in the near future.

## 688751 Spatial modeling of complex sandstone bodies to maximize reservoir contact for wells drilled in clastic formations

*A.A. Dossary and J.A. Vargas-Guzman*

The gigantic clastic reservoirs in Saudi Arabia contain thick, prolific and continuous sandstone members; however, incremental development may include numerous laterally discontinuous prolific oil-bearing sandstone bodies intercalated with non-reservoir rocks, in the so-called stringers. The optimization of hydrocarbon production requires advanced modeling workflows to identify and predict the spatial distribution of clastic discontinuous rock bodies. This study proposes cross-validation of 3-D models with new well bores to improve future predictions. The modeling approaches include sequence-stratigraphic interpretations and identification of the depositional environment. Object-modeling and sequential indicator simulation techniques were used to produce multiple realizations of 3-D geocellular facies models that predict the geometry and location of sandstone bodies. New wells were planned and drilled based on the most probable predictions. Once a well was completed, the real data collected at the wellbore was compared to multiple geocellular realizations to evaluate an average error at each location. That error was later used to modify the facies model and workflows. The ultimate goal was to reduce uncertainty and optimize new wells planning.

The proposed optimization approach, for drilling new wells, was tested in the Cretaceous Safaniya stringers member of the Wasia Formation. Upward increasing gamma-ray logging values, and upward decreasing grain size from core descriptions were interpreted to indicate fining upward sequences associated with sandstone channels. Localized crevasse splays show coarsening upward and blocky shapes on the gamma-ray. Other bodies identified are bays and mouth bars. These bodies and sequence boundaries were incorporated into an initial 3-D geocellular facies model. Object modeling was used to populate the 3-D model, with objects drawn with realistic shapes and sizes. The models were cross-validated with new drilling. Each new well provides new logging data values, which were compared to predictions from various realizations of the 3-D geocellular model, and the average error was plotted against petrophysical properties and gamma-ray derivatives. Results are summarized to recommend corrections in the geological interpretation and modeling approaches. It was concluded that a hybrid approach - combining both object and sequential indicator modeling techniques - is the optimum way to predict rock bodies with current technology.

## 680497 Utilizing massive 3-D VSP data for improved structural definition of Jurassic reservoirs in Raudhatain and Sabiriyah fields, Kuwait

*P. Dutta, J. Al-Genai, S. Kumar, S.R. Narhari, S. Al-Ashwak, A. Roberts, S. Barakat and A. Akhtar*

The Raudhatain and Sabiriyah fields are situated in North Kuwait. In the Raudhatain Field the Jurassic Najmah-Sargelu and Marrat reservoirs have two distinct northern and southern culminations, separated by an intervening fault boundary. In the Sabiriyah Field the reservoirs are divided into up-thrown and down-thrown sides along a NNE-SSW fault. In both fields, the faults and associated fracture networks have a significant impact on production. In 2009, Kuwait Oil Company (KOC) acquired two massive 3-D VSP surveys in the Raudhatain and Sabiriyah fields. The primary objective of the surveys was to improve the structural definition of the Jurassic reservoirs, especially the Marrat, and to test the feasibility of characterizing the fractured reservoirs using anisotropy. The surveys consisted of a 100-level multi-component tool, combined with around 10,000 source points covering an area of around 64 square kilometers. This is probably one of the largest onshore surveys in the region.

The high resolution and better signal-to-noise ratio in the VSP data is expected to provide improved structural definition in the vicinity of the well. This information will be utilized in locating future appraisal wells. In order to reduce the survey time, a test was also conducted on four 2-D lines of 6 km length, using four fleets of two vibrators, utilizing the high-fidelity vibratory seismic (HFVS) technique. While the processing is ongoing, the results of the test are expected to produce data quality, which will be equivalent or better than conventional methods. Based on the outcome of these surveys, future 3-D VSPs may be acquired to help in developing the fields.

## 728831 Impact of high-resolution seismic from reservoir modeling Minagish Oolite reservoir, Minagish Field, Kuwait

*A.M. Ebaid, T. El Gezeery and R. Bahuguna*

The Minagish Field has several reservoirs with oil accumulated primarily in the Lower Cretaceous middle member of the Minagish Oolite rocks (MMO). This giant carbonate hydrocarbon accumulation was discovered in 1959 and accounts for over 90% of oil production in the field. As the reservoir pressure started to decline, there was a need for water injection on the flanks of the structure to support the reservoir pressure and to increase the oil production. The sequence-stratigraphic analysis based on well logs, cores and the old 3-D seismic subdivided the reservoir into 13 geological layers with multiple phases of ooid shoal development. The Minagish Oolite reservoir has a 50 to 120 feet thick tar mat underlying the oil column. It is present in many, but not all, flank wells. It occurs at differing depths, between 9,700 ft and 9,935 ft TVDSS, and is deeper to the south of the field. The water has been injected in the layers above and below the tar mat in order to support the reservoir pressure on the crest. The well surveillance data interpretation of the injector Well MN "A" shows that layers below tar mat have very low injectivity compared with the layers above. The nearby producing Well MN "B" shows a water breakthrough in the upper layers whereas the lower layers are not affected by water. The lower oolite sediments possibly have a moderately progradational clinoforms stacking pattern which are weakly imaged by the old conventional 3-D seismic data. There is some uncertainty in the definition of flooding events between wells. In 2006, a high-resolution 3-D seismic survey was acquired to improve reservoir characterization. Progradational dipping clinoforms geometries are detected to the east of Minagish structure which led us to better definition of the reservoir architecture at this particular area in the field. This has a direct impact on Minagish Oolite reservoir modeling.

## 664240 Correlation and integration of seismic velocities, rock properties, and pore structure from outcrop of Wasia Group rocks in the United Arab Emirates

*A.H. El Husseiny, S.A. Al Mesaabi, S. Vega, M. Ali, R.J. Weger and G.P. Eberli*

An earlier geological and petrophysical investigation of the Lower Cretaceous Wasia Group in the UAE found potential correlations between seismic velocities (Vp and Vs) and fracture density, except for a group of rock samples that deviates from the general trends. The aim of this study is to better understand the previous results to improve characterization and correlation of the geology and rock properties of the exposed rock. Rock properties of 17 samples from various outcrop locations are related to different geological parameters observed at different scales, from thin sections over core plugs to outcrop dimensions. In order to achieve this correlation, we combine the following methodologies: (1) examination of 30 thin sections under the microscope trying to group samples and to find any common features that can explain any correlation with the rock properties; (2) digital image analysis (DIA) to determine quantitative DIA parameters for the description and characterization of the pore space; (3) comparison of DIA analysis and core plugs, using crossplots to investigate any other possible correlations; and (4) correlation of a shallow fully processed and migrated 2-D seismic reflection profile from the study area, outcrop stratigraphy, and rock properties.

The results show a general trend in seismic velocity-fracture density but an outliner group of samples deviates from this trend. The type of porosity seems to cause the deviation of outlier samples from the general trend. We find that all samples belonging to the outliner group have intraparticle porosity that is randomly distributed. In contrast, the porosity in the other samples is associated with fractures and/or stylolites. Moreover, quantitative DIA analysis confirms that the effect of pore spaces can be the cause of different trends of the different groups. The crossplots from the quantitative DIA analysis corroborate results of the previous work that correlated rock properties with velocities. In addition, the results display that the complexity of pore space, is related to the velocities, which decrease generally as pore spaces get more complex in terms of shape and dimensions. The quantitative DIA also shows that the more complex the pore system, the higher the fracture density. Finally, we use these results to process and interpret a 2-D seismic reflection profile to better understand the seismic response in the highly fractured exposed rocks of Wasia Group.

### 680565 Carbonate enhanced seismic mapping using post-stack band-pass frequency seismic volume filtering of two offshore fields in Abu Dhabi, United Arab Emirates

*R. El-Awawdeh, J. Zhang, Z.J. Shevchek, N. Khouri, A. Mirza, C. Harris and J. Reilly*

During recent carbonate seismic interpretation projects of two offshore fields in Abu Dhabi, UAE, several carbonate/anhydrite intervals were mapped using band-pass frequency filtered 3-D seismic volumes. Two types of band-pass filtered seismic volumes were used to enhance Eocene – Palaeocene and Cretaceous carbonate reservoir intervals, where either low-pass or high-pass frequency filters were specifically designed for the specific geologic purpose and target interval.

The first offshore field high-resolution 3-D seismic volume covers a salt-diaper-pierced shallow carbonate and anhydrite layers with complex salt-tectonic fault and karsts geometries. Interpretations for several carbonate/anhydrite intervals and faults are needed to be accurately mapped for highly deviated well-bores targeting karsted and faulted Rus (Eocene anhydrite) and Umm er Radhuma (Palaeocene carbonate) geologic intervals. Significant improvements to seismic reflections and seismically imaged shallow fault offsets (both high and low impedance reflectors) were accomplished by using a low-pass frequency filter with a 6–35 Hz range. Continuity of seismic events and fault offsets were significantly enhanced and confirmed by well-ties and subsequent time/depth conversion model. The second offshore field 3-D seismic volume covers a giant oil field where the main seismic mapping targets are the faulted Kharaib (Cretaceous carbonate) reservoirs. Again significant improvements of seismic continuity and fault-offset images were accomplished by using a high-pass frequency filter with a 60–100 Hz range. The key objective of this presentation is to show the significance of certain seismic frequency ranges which enhance specific geologic features at both early and late carbonate depositional systems. The presentation also explains the workflow developed specifically to tackle seismic frequency ranges for drilling and reservoir characterization in carbonates.

### 684529 Horizontal wells optimize production in a super K sandstone reservoir Minagish Field, West Kuwait

*T. El-Gezeery and A. Ismael*

The Burgan reservoirs in the Minagish Field are clastic sandstone reservoirs with super-K permeability. The upper reservoir layer consists of fluvial sandstones with grain sizes ranging between medium to coarse. The average porosity is about 28 to 35% and the average permeability varies between 0.7 to 10 Darcy. This reservoir has been a production challenge due to early water breakthrough resulting from coning. We present a case study in which horizontal well technology has been used to mitigate risk of water coning besides enhancing productivity. At the early stages six vertical wells were completed in the Burgan reservoirs with low production rates. Water coning was a major problem because of the homogeneous massive nature of the sand bodies that probably have vertical to horizontal ratios (Kv/Kh) close to 1. The high ratio between the oil viscosity and the water viscosity is also a major reason for coning. Although the first horizontal well drilled in 2005 (with 950 feet of net pay) achieved unprecedented production rates, its production life was short. Water coning and early water breakthrough was due to several factors: (1) low stand-off with the oil/water contact (OWC); (2) high off-take rates; and (3) the presence of a fault acting as a conduit. The second horizontal well was completed at the uppermost part of the reservoir where the facies grade from marine siltstones and shales to fluvial clean sand package. Only 300 ft of the heel out of 1,000 ft horizontal section has been penetrated. Based on the study sweet spots were defined by taking into account: (1) control on production rates; (2) stand-off from the overlying marine shale; (3) level of the oil/water contact; and (4) absence of significant faulting. Five horizontal wells were drilled and successfully completed in targeted sweet spots, achieving a dry oil production and minimizing the possibility of water coning.

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## 694160 Integrating rock physics, seismic reservoir characterization and static modeling of carbonates: A case study from the United Arab Emirates

*F. El-Wazeer, A. Vizamora, A. Al Hamedi, H. Al-Housani, P. Abram and S. Busman*

An integrated workflow to generate seismically constrained reservoir models is described. Several key technologies were used including carbonates rock physics estimation, seismic forward modeling and comparison to surface 3-D seismic, as well as probabilistic seismic inversion. Using the SUN rock model as a framework, the team derived relationships between the reservoir properties (e.g. modeled facies, porosity and fluid content) and the elastic properties (compressional and shear wave velocities, and density). The theory of the SUN model was chosen as a key for relating reservoir properties to seismic: relations were identified between SUN's frame flexibility factor (describing the elasticity of the rock frame determined by pore geometry), velocities, densities and porosities. Those relations were compared to the information on sedimentology, diagenesis, structural position and reservoir rock types. Detailed well to seismic matching enabled estimating a fit-for-purpose average wavelet to be used over the entire field. The fluid substitution of the well logs, log blocking, and the fluid properties made it possible to model the fluid content impact on the seismic, and to better understand the impact of peg-leg multiples still present in the seismic data.

The generation of 3-D synthetic seismic, based on the static model, included the use of the relations obtained from the rock physics model, the well-log blocking and the derived seismic wavelet. The match between real and modeled synthetic seismic indicates how well the parameters in the static model describe the reservoir, and the relevance of the variables (rock and fluid properties, layering, and wavelet) included in the forward modeling. The seismic match was improved by iteratively fine-tuning the different variables used to generate the synthetic seismic. The optimization process highlighted which variables control the seismic response. These were subsequently used to define the stochastic parameters and the uncertainties in the probabilistic seismic inversion. The inversion algorithm utilizes the constrained static model as input and can invert to any of the variables present in it. Therefore it was possible to obtain probability distributions for porosity, fluid saturation and rock rigidity in any location of the reservoir that match the seismic. The workflow was applied to the Bab Field in Abu Dhabi, UAE. The resulting static model more accurately reflects the lateral variability of the rock properties while preserving vertical resolution.

## 680598 Geological modeling of complex fluvial lacustrine system: Case study from an oil field in Central Muglad Basin, Sudan

*M.M. Elamhi and A.M. Mohamed*

Sudan is the largest country in Africa with an area of 2.5 million sq km and shares a common border with eight countries. The Muglad Basin is a NW-trending rift basin in Central Sudan. The Greater Nile Petroleum Operating Company (GNPOC) operates blocks 1, 2 and 4, which lie in the central part of this basin. The Muglad Basin is characterized by more than 15,000 m of non-marine clastic sediments, which in the study area are likely to be sourced by northern and eastern paleo-highlands. The combination of both continental (reservoir) and lacustrine (seal/source) rocks in conjunction with the tectonics has created favorable juxtaposition of source, reservoir and seal.

The area of study has been a technical challenge to the operating company. A team from GNPOC and Sudapet has conducted geological modeling for the three main Upper and Lower Cretaceous reservoirs, namely the Aradieba, Bentiu and Abu Gabra formations. The study comprised a 3-D stratigraphic, facies and structural model building for the key horizons using Petrel software to capture reservoir variability. Seismic attributes gave a clear expression of faulting and show that all the productive wells are located on a low frequency and low to high amplitude reflection. The core data used in this study were correlatable with the petrophysical interpretation models. This oil field has multiple oil/water contacts. The modeled petrophysical properties were constrained by facies. The static model identified sand bodies' architecture that yielded an increase in both oil originally in-place (OOIP) and estimated ultimate recovery (EUR).

## 727747 Reservoir characterization of Fadhili Reservoir, Awali Field, Bahrain: A case study

*M. Faqihi, R.N. Govinda Rao, S. Kumar, E. Jaber, H. Baqer, A.E. Al-Muftah and K. Kumar*

This presentation describes a practical approach that led to improved production from one of the unexploited reservoirs in the Awali Field and increased its potential recovery. The Fadhili reservoir, a Middle Jurassic carbonate, is about 185 ft thick and overlain by tight Dhruma limestone, with an oil column of 50–70 feet in thickness. The reservoir quality is good in the top three stratigraphic layers but progressively deteriorates towards the base of the reservoir. The low formation resistivities in the oil-bearing zones are attributed to the high formation-water salinity, which makes the formation evaluation difficult.

Vertical wells begin production with low water cut, which gradually rises to more than 95% during the course of production. Six vertical wells drilled in this reservoir have produced 156 million stock tank barrels pf oil to date. Initially, based on the poor performance of the vertical wells, the Fadhili was thought to be a poor prospect. However, a simulation model built to study the production behavior of the reservoir indicated that the production potential can be increased if an appropriate well type is chosen for this reservoir.

Based on this study and to ensure maximum reservoir contact, a horizontal well was drilled, targeting the top 10–20 feet of the oil column, to evaluate oil production potential of the reservoir. During the last six months, this horizontal well alone has produced more than the total production of all the six vertical wells drilled in the past. The encouraging production results (high on oil/low on water) prompted a review of the geological model and petrophysical properties of the reservoir for: (1) better reservoir characterization; (2) identifying reservoir flow units; and (3) estimation of reserves.

## 727742 Role of sedimentology and petrography in the development of Khuff reservoirs, Awali Field, Bahrain: A case study

*M. Faqihi, S. Kumar, R.N. Govinda Rao and I. Jaber*

This presentation highlights the petrography and sedimentology study carried out for Khuff gas reservoir of Awali Field. The topics include a review of the core analysis including electrical, sonic and full bore formation micro imager (FMI) logs, as well as X-ray diffraction (XRD) and scanning electron microscope (SEM) studies. The study helped to explain the mineralogy, dolomitization, diagenesis and evolution of the pore system of the reservoir. The study indicated four different facies: (1) Peloidal-lime-grainstone to packstone, skeletal lime grainstone facies which is interpreted as being very coarse grained, deposited in a relatively high energy, shoal environment; (2) Bioturbated-lime-mudstone and lime-wackestones facies, which are interpreted to be that of lagoonal environment; (3) Dolomudstone facies, with dolomitized mud supported sediments are interpreted as shallow, restricted lagoon in a supratidal setting; and (4) Dolopackstone facies, interpreted as being deposited within a shoal environment.

The depositional environment is identified as lagoonal during transgressive phase and shoal during regressive phase. The diagenesis is dominated by compaction indicated by tight textures in mud-rich samples and deformation of framework grains. Porosity enhancement is seen due to the grain dissolution and rare fracturing while porosity destruction is carried by compaction of sparse calcite cement and dolomite. Calcite is the dominant mineral in some samples. The clay content is found to be very minor. SEM analysis showed the presence of good porosity including inter-particle and inter-crystalline porosity. The average porosity is about 17% and the permeability is about 60 mD. Very few fractures are observed in this formation. This integrated study helped in understanding the reservoir heterogeneity and its potential based on which current wells were appropriately completed. This will also aid in productively completing future wells.

## 680939 Image petrophysics: A new approach to reservoir characterization

*M. Frass and N. Harvey*

Borehole imaging is the only tool to characterize from very small features like fractures or cross bedding up to major structural features. Since the late 1980s, borehole imaging based on resistivity measurements has been the only tool with the vertical and horizontal resolution, capable to detect very small bioturbation effects, cross bedding, vugs and or fractures as well as other structural features such as faults, unconformities or folds. The main question about this technology has been, how deep into the formation these small features really are and how they impact the hydrocarbon production.

There are only a few methods to evaluate the fracture extension or the cross bedding effect within the sand bodies over the reservoirs: (1) a dynamic interference test among two or more wells and (2) the use of seismic attributes and neural networks to correlate with image logs and/or core data. From the images the fracture orientation, spacing, and aperture are obtained, which could be used to calculate fracture porosity and permeability as well as vugular porosity and permeability distribution around the well bore. Using image petrophysics, each resistivity curve is transformed into a porosity curve generating an azimuthal property distribution map defining the vertical and the horizontal anisotropy of each interval of the reservoir. Using this extremely powerful method and integrating with seismic attributes is the most advanced method to generate a 3-D reservoir model, in any reservoir.

## 691737 Effects of microfacies and diagenesis on petrophysical properties of Sarvak Formation, Fars Area, southern Iran

*P. Gholami Zadeh and M. Adabi*

The Lower to Upper Cretaceous (Albian – Turonian) Sarvak Formation, the second major oil and gas reservoir in Zagros Basin of southern Iran, is principally composed of carbonates with minor shale. Fifteen microfacies were recognized from 287 meters of core, and 329 thin sections (colored with red Alizarin) were collected for petrographic analysis, together with analysis of core and well logs. Petrophysical properties of carbonates are controlled in part by the original depositional texture, but also largely by subsequent diagenetic processes. The sedimentary and diagenetic processes together control the arrangement, distribution and orientation of the major constituents, the open space and pathways, the fractures and the stylolites in the rock. When working with reservoir quality of carbonate reservoir rocks, these main fabric elements have to be considered.

In this study, the microfacies were deposited in lagoon, back reef (leeward), reef, fore reef (seaward), shallow open marine and deep open marine settings. The petrographic analyses indicate that the Sarvak Formation carbonates have undergone a complex diagenetic history which includes compaction, cementation, dissolution, dolomitization, neomorphism and fracturing. Cementation and compaction reduced porosity, which led to low permeability and poor reservoir quality. Dissolution, dolomitization and fracturing diagenesis processes improved reservoir quality. The dissolution process generated secondary porosity consisting of vuggy and moldic types. While this has had an important effect on increasing porosity, the most important factor in the development of the reservoir has been fracturing.

In lagoonal deposits, a single unit was distinguished with moldic and vuggy porosities. In shoal/reef deposits, two units were distinguished in terms of dissolution and grain frequency. In shallow open-marine deposits, two units were identified with different degrees of fracturing and dolomitization; while deep open-marine deposits were characterized by a third unit in terms of stylolitization and dolomitization. Consequently, the shoal/reef deposits with rudist grainstone and rudstone textures and interparticle and moldic porosities had the best reservoir quality. The key challenge in this reservoir analysis was to predict the vertical distribution of petrophysical properties to improve reservoir characterization. This research improved our understanding of geologic controls on the reservoir performance.

## 680624 Multi-scale imaging process for computations of porosity and permeability from carbonate rocks

*A.S. Grader, A. Nur, C. Baldwin and E. Diaz*

Reservoir rock material collected during drilling is one of the main sources used to derive reservoir fluid transport and rock mechanics properties. Carbonate reservoirs may have heterogeneities that create multi porosity/permeability systems that are very difficult to describe, and to determine their flow properties. Conventional methods use laboratory procedures to perform experiments that directly or indirectly yield required rock properties. Some of these procedures, such as the determination of relative permeabilities, may take several months to perform. Also, in some cases, it is very difficult, or impractical to perform the experiments in the first place. Yet, as reservoir characterization is becoming ever more important for oil and gas production, a much larger portion of reservoir rocks, from cuttings to full cores, will need to be analyzed than what are currently evaluated. This study offers an example of the use of digital rock physics to determine porosity, permeability, and relative permeabilities for a carbonate sample using multi-scale imaging. Digital rock physics using the Lattice Boltzmann (LBM) for fluid dynamic calculations is at a point where for a proper digital pore space the resulting calculated flow properties are reasonably correct. The main issue facing digital rock physics is the need to up scale the computed properties to the scale of the core.

The process presented in this study includes sample preparation, imaging, image processing, property computations, and property integration to the core scale. The sample is subjected to a descending scale of X-ray CT imaging, along with physical sub-sampling of the core. The descending size of scanning leads to increased resolution of the three-dimensional digital core, keeping the sample volumes registered in place. The resulting digital rocks are segmented and the pore structure is determined on the X-ray CT grid system. The resulting three-dimensional pore structure, that is the same as the actual pore structure subjected to resolution limits, is used as the input grid system for direct fluid dynamic computations that are second-order accurate representation of the Navier-Stokes fluid flow equations. These computations yield porosity, absolute permeability, relative permeabilities, and capillary pressure. In this study we focus only on porosity and permeabilities. Multiple scale imaging permits the estimation of permeability at the core scale.

## 681083 Workflow from seismic to static modeling capturing key heterogeneities impacting production performance in a super-giant Middle East carbonate field

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Building a full-field static model in a super-giant oil field with more than 700 wells and 47 years of production history is a challenging task, especially when the main reservoir spans three distinct sedimentological domains with their own complexities and production issues. Oil is produced from an Aptian carbonate reservoir averaging 400 ft in thickness with complex internal reservoir architecture. The lower reservoir units comprise continuous platform and ramp carbonate layers deposited during overall transgression. A platform dominated by stacked patchy rudist build-ups and inter build-up ponds developed in the south of the field during later aggradation. Rapid water advance along high-permeability layers led to irregular water fingering which must be captured in the static and dynamic models. Facies architecture and property distributions are very different in the central highstand progradation and northern late highstand clinoform domains dominated by more steeply dipping reservoir units (1–3 degrees). Non-reservoir carbonate mudstones associated with transgression form local flow barriers confirmed by pressure and production data.

Different strategies were used in structural and property model building to account for heterogeneities across the field. The southern platform interior with rapid facies variations of non-reservoir 'pond' facies and stacked coral/rudist shoals was modeled using well data combined with seismic attributes. Production in the north is supported by peripheral water injection, water alternating gas (WAG) pattern and line-drive gas injection. Deterministic mapping of third- and fourth-order clinoform sequences is critical for understanding fluid movement. A key modeling challenge was to accurately represent the clinoform geometries. With dips up to 3 degrees downlap of layers occurs within 1–2 km, resulting in ambiguous well-based correlations. High-quality seismic data was used to map clinoform 'corridors' and constrain reservoir thickness. Stochastic methods (SGS) guided by a deterministic layering framework and controlled by a core/log-based lithofacies model were used to populate the petrophysical properties. The central area comprises a thick succession of good reservoir quality facies with 'transparent' seismic character. Recent seismic analysis has led to the recognition of clinoforms although they could not be mapped deterministically. An architecture was established using well correlation guided conceptually by the overall clinoform shape.

## 680049 FMI sedimentological interpretation, Western Desert, Egypt: An approach for high-resolution facies reservoir anatomy

*E.G. Haddad and M. Abdel Fattah*

The Bahariya Formation in the Western Desert is one of the major complex oil-bearing reservoirs in Egypt. Many discoveries have revealed the high oil potential in this formation. Detailed sedimentological interpretation was performed over the imaged highly complicated and inconsistent reservoir interval for Abu Roash "G" Member and Bahariya Formation in two drilled wells. Twenty lithofacies types were defined from the images of the two investigated wells. Individual lithofacies were defined based on detailed description of sedimentary structures from the image logs. The sand lithofacies of the Bahariya Formation and dolomite of Abu Roash "G" Member were assigned pay values. The identified electrofacies are calibrated with the cored intervals in one of the two wells.

The Bahariya Formation in the studied two wells is interpreted as a tidal flat deposit and characterized by the following subenvironments: barrier bars, tidal channel and tidal flat muds. The Abu Roash "G" Member is considered as a subtidal carbonate and characterized by the presence of frequent secondary dolomite. Correlation is based mainly on the data gained from formation micro imager (FMI) sedimentological facies analysis and interpretation has been carried out to throw light on the lateral facies changes and consequently to solve many problems related to the reservoir complexity. The missing of some facies associations confirms the presence of faulting.

## 681051 Recognition of palaeoexposure surfaces within Cenomanian – Turonian strata of southwestern Iran: Implications for reservoir characteristics

*E. Hajikazemi, I.S. Al-Aasm and M. Coniglio*

Stable carbon and oxygen isotopes and $^{87}Sr/^{86}Sr$ ratios determined in surface and subsurface carbonates of the Sarvak Formation reveal the presence of multiple subaerial exposure surfaces that resulted from sea-level fluctuations. The sequence boundaries exhibit different degrees of geochemical alteration with more extensive alteration representing longer duration of subaerial exposure. Most of the $\delta^{13}C$ (range from -6.4‰ to 4.1‰, VPDB) and $\delta^{18}O$ values (ranges from -9.4‰ to -0.9‰, VPDB) determined for Sarvak matrix carbonates fall well within the mid-Cretaceous marine values while the palaeoexposure surfaces are characterized by more negative values (i.e. $\delta^{13}C$ = -6.4‰ and $\delta^{18}O$ = -9.4‰ VPDB) and higher $^{87}Sr/^{86}Sr$ ratios. The most depleted $\delta^{13}C$ values in carbonate palaesol formed due to subaerial exposure resulted from interaction of marine carbonates with aggressive meteoric water charged with atmospheric $CO_2$. This interaction also caused pronounced dissolution and karstification and development of favorable reservoir characteristics including effective porosity and permeability.

## 648232 Neural permeability prediction of heterogeneous gas sand reservoirs

*G.M. Hamada and M. Elshafei*

Analysis of heterogeneous gas sand reservoirs is one of the most difficult problems. These reservoirs are usually produced from multiple layers with different permeability and complex formation, which is often enhanced by natural fracturing. Therefore, using new well logging techniques like nuclear magnetic resonance (NMR) or a combination of NMR and conventional open-hole logs, as well as developing new interpretation methodologies are essential for improved reservoir characterization. NMR logs differ from conventional neutron, density, sonic and resistivity logs because the NMR measurements provide mainly lithology-independent detailed porosity and offer a good evaluation of the hydrocarbon potential. NMR logs can also be used to determine formation permeability and capillary pressure.

This study concentrates on permeability estimation from NMR logging parameters. Three models used to derive permeability from NMR are Kenyon model, Coates-Timer model and Bulk Gas Magnetic Resonance model. These models have their advantages and limitations depending on the nature of reservoir properties. This study discusses permeability derived from Bulk Gas Magnetic Resonance model and introduces neural network model to derive formation permeability using data from NMR and other open hole log data. The permeability results of neural network model and other models were validated by core permeability for the studied wells.

## 677890 Petrophysical properties evaluation of tight gas sand reservoirs using integrated data of NMR, density logs and SCAL

*G.M. Hamada*

Many tight formations are extremely complex, producing from multiple layers with different permeability that is often enhanced by natural fracturing. The complexity of these reservoirs is attributed to: (1) low porosity and low permeability reservoir; and (2) the presence of certain clay minerals like illite, kaolin and micas in pores. Evaluation of tight gas sand reservoirs represents difficult problems. Determination of petrophysical properties using only conventional logs is very complicated. Nuclear magnetic resonance (NMR) logs differ from conventional neutron and density porosity logs. NMR signal amplitude provides detailed porosity free from lithology effects and radioactive sources and relaxation times give other petrophysical parameters such as permeability, capillary pressure, the distribution of pore sizes and hydrocarbon identification. Using of NMR on an individual basis or in combination with density log and SCAL data provides better determination of petrophysical properties of tight gas sand reservoirs.

This study concentrates on determination of three petrophysical parameters of tight gas sand reservoirs: (1) Determination of detailed NMR porosity in combination with density porosity, DMR. It is found that DMR porosity method is a gas corrected porosity, and independent facies porosity model. (2) NMR permeability, KBGMR, is based on the dynamic concept of gas movement and bulk gas volume in the invaded zone. It is concluded that KBGMR is a facies independent technique, and this is the most important value of this technique. (3) Capillary pressure derived from relaxation time T2 distribution could be used for formation saturation measurements especially in the transition zone. It is found that the assumptions of capillary pressure approximation from T2 distribution can be applied in gas wells as well with some consideration due to gas and mud filtrate effects.

## 670977 Shaybah 3-D amplitude inversion with interbed multiple modeling

*M. Hong, H. Mohd Noor and M. Hedefa*

Seismic amplitude inversion has been routinely used throughout the industry to help assess the reservoir quality and derive reservoir properties such as porosity. In cases where interbed multiple contaminations interfere with the primary reflectivity, the inversion results are questionable unless interbed multiples can be simulated in the inversion procedure. In this study, we demonstrate the use of zero-offset modeling, to simulate interbed multiples, observed in a 3-D seismic dataset, acquired over the Shaybah oil field. We identified the interval from which interbed multiples were generated and produced a reasonable 3-D impedance model for use in the field's development drilling program.

A "layer-stripping" type modeling approach was used to identify the interval from which the interbed multiples were generated. Three key geologic intervals between the surface and the base of the reservoir were identified as candidates for the starting layer from which the interbed multiples were modeled. To begin, the shallowest formation of the three was designated as the starting layer. Synthetic traces with primary and interbed multiple reflections were generated and compared with the measured seismic data. This procedure was repeated for the deeper two consecutive formations. At the conclusion of this modeling exercise, it was determined that using the shallowest formation as the starting layer produced the best match between the synthetic and measured seismic data.

The inversion algorithm used a model-based method where the starting model was generated by interpolating known log impedances between existing well control based on the interpreted seismic time horizons. The initial model was then optimized by iteratively updating the impedance to minimize the error between the synthetic, generated from the model, and the seismic. The final inversion results were evaluated by matching the measured 3-D seismic data to the impedance logs at the wells. Comparison of seismic and inverted impedance volumes showed that the top of the reservoir was more clearly defined by the impedance volume; whereas the 3-D seismic signature for the top of the reservoir is poorly defined due to the presence of the multiple interference.

## 705497 Evaluating the petrophysical parameters of carbonate reservoirs, offshore Abu Dhabi, using conventional core analysis from different scales of core samples

*K.I. Hosani, C.T. Lehmann, M. Ibrahem and M. Ouezzani*

A detailed conventional core analysis (CCA) was performed on Jurassic carbonate reservoir samples from a new offshore field in Abu Dhabi. The conventional core analysis study included porosity and permeability measurements on plugs samples, mercury injection capillary pressure (MICP), core description, and a reservoir characterization study. Different types of conventional core data were collected, evaluated and incorporated. The study was performed in order to define depositional environment, facies, and the distribution of reservoir rock types. This data was then used to define the flow units, which are the building block for a 3-D geological model. Limestone reservoir samples are highly complex and reservoir quality is controlled by the presence of mud and the amount of diagenesis. In addition, dissolution of semi-stable biogenic components, such as stromatoporoids, is creating vuggy porosity. This raises the question: Does a plug sample of the reservoir reflect the petrophysical characteristics of the reservoir and its flow performance?

The CCA study was performed on 1.5 inch plugs (historic data) and 2.5 inch plugs (more recent data). Sampling often avoids vuggy, fractured and highly cemented areas of the core. The studied field is faulted and reservoir quality might be affected by late stage diagenesis. In addition, certain reservoir facies, such as stromatoporoid build-ups exhibit large-scale vuggy porosity. So, plugs are often not the best sampling technique to represent the reservoir in order to determine petrophysical characteristics and ultimately the flow performance.

Whole core samples which are representing different lithofacies types were selected from 2 wells to measure porosity & permeability and conduct CT scans. The whole core data will be used to generate a relationship with plug-size data to allow upscaling the permeability to be consistent with the dynamic well flow test data while maintaining the vertical contrast of permeability, which is crucial in characterizing the flow dynamics of a stratified reservoir. Comparing the petrophysical parameters using different scales of reservoir samples (plugs *versus* whole core) might help to address the role of large scale features such as fractures and diagenesis (vugs and its connectivity) on reservoir performance and reduce, therefore, the petrophysical uncertainty in the reservoir models.

## 680837 Biosteering the Upper Permian Khuff C reservoirs in Saudi Arabia

*G.W. Hughes, S.S. Al Enezi and S. Rashid*

Coiled-tube, under-balance drilling is being used to improve gas and condensate recovery from the Khuff C reservoir in Haradh area of southern Ghawar Field. The 2 5/8 inch diameter coiled-tube inhibits access of conventional wireline logging tools except gamma and LWD, and the only source of stratigraphic control is micropalaeontological and petrographic data gathered while drilling, referred to as biosteering. Recent experience has shown that coiled-tube drilling can successfully be steered using rapid thin-section production with micropalaeontological and petrographic analysis of cuttings samples. Stratigraphic location is achieved by reference to a local biozonation based either on core or cuttings samples from the mother bore or adjacent wells. Although of shallow-marine origin, Khuff C depositional environments were found to be highly varied over short distances, and it is necessary to establish reference biofacies-based biozonations for each well using, where possible, the closest cored well. Stratigraphic control is possible to within 2 ft vertical accuracy, and enables near real-time critical instructions to be communicated to the directional driller ahead of the gamma data. As the “eyes” of the drill, this technique has enabled maintenance of the bit within the target reservoir and resulted in significant increase in gas and condensate production.

## 677891 Co-krigged porosity modeling exhibits better results than conventional regression analysis and multiattribute transform porosity models

*A. Hussain and A. Rasheed*

Reservoir heterogeneity characterization is always a real challenge for the sub-surface professionals. Although there is no direct way to assess the true heterogeneity, still certain models can imitate the important features of variability. The spatial distribution of reservoir properties can be determined by stepping through a workflow which starts where standard workstation seismic and geologic interpretation end. In order to obtain the most accurate and detailed results, one must design a multidisciplinary workflow that quantitatively integrates all the relevant subsurface data. This study demonstrates the enhanced results of regression analysis and the multi-attribute transforms which are used for porosity prediction in one of the areas in Middle Indus Basin. The co-krigging method used in geostatistics has been applied to derive a combined effect of both the techniques. The dataset used for this study consists of the available well data including VSP and the petrophysical logs, a 3-D seismic volume consisting of both reflectivity and inversion data for attribute extraction. A conventional regression analysis using the single polynomial function incorporating the AI and the well porosities were used to extrapolate the average porosities away from the known control points. We then applied the multi-attribute transform using various seismic attributes and the well data. A cross-validation of porosity with the significant seismic attributes was done through neural networking. The results were then applied to derive initial porosity map. Both the results were integrated using co-krigging approach which involved creation and comparison of different variograms to get the enhanced version of porosity model. The co-krigged porosity maps showed a better delineation of good porosity zones as compared to initial porosity maps.

## 705318 Oil-to-oil correlation studies in Marun and Kupal oil fields (southwest Iran) using gas chromatography-mass spectrometry-mass spectrometry (GC/MS/MS)

*H. Jafary and M. Kamali*

Marun and Kupal oil fields are situated southeast of Ahwaz city, next to Agha Jari and Ahwaz oil fields, and are among the largest oil fields in the Dezful Embayment. The Sarvak Formation constitutes the main reservoir. In order to investigate the geochemical characteristics, the distribution of "molecular fossils" (biomarkers) in extracts from some specific geologic age in the Marun and Kupal basins have been analyzed and used as the fingerprints for the oil-oil and oil-source correlation. Obviously, not any molecular fossil related to source and environment can be used as the fingerprints for oil-oil correlation. Some special biomarkers are common in the extracts in the Sarvak reservoir and showed obvious similarity in both reservoirs, including dinosteranes (m/z=414-98), desmethylsteranes (m/z=414-217), methylsteranes (m/z=414-231), C24 norcholestanes and C28 Steranes originated from dinoflagellates and diatoms. The great similarity of the relative contents of these compounds between the marine oils produced in Sarvak reservoir of Kupal and Marun oil fields suggests that the Middle Triassic is the likely main source for the Sarvak reservoir in the studied fields. Based on maturity and source rock lithology parameters of biomarkers, the candidate source rock(s) are carbonates deposited in anoxic conditions and thermally mature.

## 680878 Characterization of glaciogenic reservoirs using high-resolution quantitative mineralogical and textural analysis of drill cuttings

*A. Janszen, A. Moscariello, M.R. Power and J. Sliwinski*

In the past decade Palaeozoic glaciogenic deposits in North Africa and the Middle East have been recognised as important reservoirs for hydrocarbons. However, the sedimentary system associated with glaciers and ice-sheets is highly complex and still poorly understood. This often results in large exploration and development risks due to potentially large uncertainties in the reservoir stratigraphy, facies and 3-D architecture. Glaciogenic reservoirs are often associated with deeply incised valleys (i.e. tunnel valleys). These are formed under ice-sheets by overpressured meltwater and can reach up to 600 meters in depth, tens of kilometers in length and 5 kilometers in width. As the sedimentary mechanisms and depositional environments can be highly variable, the subsequent infill of the valleys is vertically and laterally extremely heterogeneous. The heterogeneity of the sedimentary infill often results in problematic subsurface correlation. This is made even more difficult by the absence of biomarkers or marker beds that can be traced on a regional scale.

Under the Pleistocene ice-sheets of NW Europe, tunnel valleys with similar characteristics to those from the Palaeozoic age were formed. In the city of Hamburg (NW Germany) there is good understanding of the architecture and lithology of the infill of the Pleistocene tunnel valleys due to a database of ca. 17,000 boreholes that were mainly drilled for geotechnical investigations. This study presents the results of a detailed sedimentological and mineralogical study of one of these boreholes. 170 cuttings samples were analysed using QEMSCAN®. This automated instrument uses a combination of backscattered electron imaging and energy dispersive X-ray spectroscopy to mineralogically and texturally quantify samples. Mineralogical and textural trends were identified and correlated with the available wireline logs. Grain-size was compared with the reconstructed density and porosity logs and used to differentiate potential reservoir flow units.

Mineralogical composition provided an indication of the provenance at different stratigraphical intervals. Diagenetic minerals such as clay and secondary cement infills were also investigated to assess whether such elements could be used for correlative purposes. This study highlighted the compositional heterogeneity of tunnel valley infill and confirmed the potential of QEMSCAN® as a tool to unravel complex stratigraphy and quantify reservoir potential.

## 743106 Reactive transport models of structurally controlled hydrothermal dolomite: Implications for Middle East carbonate reservoirs

*G.D. Jones, I. Gupta and E. Sonnenthal*

Hydrothermal dolomitization is present in several Middle East carbonate reservoirs including Ghawar, the North Field and South Pars. Structurally controlled hydrothermal dolomitization describes the replacement of limestone with dolomite and/or the precipitation of dolomite cement and associated MVT minerals (anhydrite, sulfides, quartz and fluorite) as a consequence of subsurface brines that ascend upwards through fault and fracture systems. This fluid rock interaction in the burial environment has the potential to both improve and/or degrade reservoir quality depending on the properties of the host rock, fluid composition, timing of fluid flow and spatial position relative to structure.

A reactive transport model (TOUGHREACT) that couples fluid flow with chemical reactions, was used to simulate hydrothermal dolomitization. Specifically we investigated the sensitivity of hydrothermal dolomite to: fault permeability/flow rates of ascending fluids, reservoir heterogeneity (alternating high and low permeability strata), temperature of host rock and ascending fluids (including their relative temperature difference), fault spacing/multiple fault scenarios, fault vertical separation and strata juxtaposition, episodic *versus* continuous brine injection and subsurface brine composition (in particular, Na-Cl *versus* Ca-Cl brines).

Results from 2-D and 3-D models suggest that diagenetic modification and evolution of petrophysical properties in response to hydrothermal dolomitization are a complex function of the hydrodynamics and fluid chemistry. Variations in fault and matrix permeability strongly control the spatial patterns of diagenesis. Brine chemistry of both the host rock and the ascending fluids affect the extent and distribution of dolomitization. Na-Cl brines produce more dolomite than Ca-Cl brines because of higher Mg/Ca ratios but this result is salinity and temperature dependent. Hanging wall fault blocks are preferentially dolomitized. Depending on their permeability, relay zones between faults may remain undolomitized. For the systems simulated, hydrothermal dolomitization enhances matrix porosity and permeability but fault zones begin to seal due to the precipitation of anhydrite and dolomite cement. Breccia, vugs and fracture pore types that are commonly observed in hydrothermal dolomites are beyond current simulation capability. Thus predictions of reservoir quality from reactive transport models may be less useful than predictions of hydrothermal dolomite geobody dimensions.

## 706210 Sedimentology and diagenetic history with reference to reservoir quality, Triassic Lower Jilh (Kra Al Maru Reservoir), Kuwait

*D.A. Khan, M. Al-Ajmi, A.H. Sajer and R. Husain*

The name Kra Al Maru has been assigned to the additional unit at the lowermost part of the Middle Triassic Jilh Formation in Mutriba and Kra Al Maru area in western Kuwait. Stratigraphically the interval corresponds to the Jilh C Member of the Jilh Formation, and it is divisible into lower (KM-B) and upper (KM-A) units. Microfacies comprise anhydrite, dolomudstone, dolowackestone, argillaceous dolostone and dolomitic shales with minor dolopackstone, dolograinstone, lime mudstone, lime wackestone. Carbonaceous matter and terrigenous material is present at places. Anhydrite is present as early nodules and crystals, as well as late cement and vug fillings. Facies associations of both units are bioturbated, highly variable with common organic matters. The distinguishing feature of the lower unit (KM-B) is having less anhydrite than the upper unit (KM-A). The lower unit was deposited in intertidal to subtidal and lagoonal environments, as a shallowing upward sequence that grades upward to algal laminated wackestone and anhydrite. The presence of few sub-aerial exposure surfaces indicates dissolution that might have developed at the end of cycle and is indicative of slightly humid conditions. The upper unit was deposited in an intertidal to supratidal, sabkha environment under arid climate. Diagenetic events include compaction, dolomitization, and replacement by anhydrite, fracturing and stylolization. Primary porosities were reduced by compaction, overdolomitisation and late stage cementation. Both cemented and uncemented fractures are observed in the core and microfractures are seen in core plugs and have led to increased fracture porosity and permeability. The lower unit is ranked and pursued as new prospective units within the Jilh Formation.

## 682471 Application of magnesium yield measurement from neutron spectroscopy tool in formation evaluation of northern Kuwait fields

*D. Kho, M. Al-Awadi, M.N. Acharya and S. Al-Ajmi*

Evaluation of porosity and lithology has always been done through a combination of density, photoelectric factor (PEF), neutron, gamma-ray, and sonic measurements. None of these directly gives porosity or lithology. Therefore, common practice includes building petrophysical models to extract these reservoir properties. Geoscientists involved in petrophysical analysis using multi-mineral solvers are aware of the difficulty and the uncertainty of the process; for example, changing a fluid property in the model will change the lithology as well as the porosity. The logs themselves are also known to have their own measurement uncertainties. The density log, for example, is affected by bad hole, lithology, barite, and light hydrocarbons. The neutron log is affected by lithology, fluid hydrogen index, and the borehole properties (temperature, pressure, hole size, stand-off, mud cake, mud weight, etc.). The interpretation is also complicated by the fact that different neutron tools from different logging companies have different sensitivities to lithology. Sonic log data is also used for interpretation even though it is affected by fractures, vuggy porosity, anisotropy, etc. The PEF curve is commonly used as an additional tool to solve for the lithology. However, if the mud contains barite the measurement becomes unusable.

Dolomite and solid bitumen quantifications have been the challenging issues in carbonate evaluation. The dolomite diagenesis involves the recrystallization which makes the dolomite less susceptible to porosity reduction caused by overburden pressure. This unique characteristic of the crystallized dolomite makes it an important reservoir rock especially in deep carbonate reservoirs. On the other hand, the presence of solid bitumen is always associated with poor reservoir quality. Also, the physical properties of the solid bitumen cause it to appear as hydrocarbon. If not corrected, the formation evaluation result will give incorrect porosity and water saturation computation.

New development in neutron capture spectroscopy tool provides significant data to quantify the mineralogy in carbonate, especially the dolomite content through magnesium yield measurement. Combination of the spectroscopy data and magnetic resonance data can be used to identify and correct the solid bitumen effects. Real examples from deep carbonate reservoir in northern Kuwait fields and the validation against core data will be presented.

## 705007 Diagenetic history and isotope geochemistry of Pabdeh Formation in Dezful Embayment, southwest Iran

*M. Khoshnoodkia, H. Mohseni and I.S. Al-Aasm*

The Upper Eocene – Oligocene Pabdeh Formation is a carbonate-dominated sedimentary package with shale-marl intervals. This formation was studied in the type section (Kuh-E-Gurpi) and four boreholes located in Dezful Embayment (Zagros Basin). The formation comprises three depositional sequences bounded by a Type I sequence boundary in the lower part and both Type I and Type II sequence boundaries in the upper part. The uppermost sequence experienced a subsea marine phreatic diagenetic environment, whereas sequences one and two evidently experienced burial diagenesis with moderately reducing conditions in a relatively enclosed system. $^{87}Sr/^{86}Sr$ ratios represent a sharp separation between sequences two and three, whereas low Rb content of these samples suggests these sediments were not affected by meteoric fluids in an open system. A duality of behaviour is expected from the Pabdeh Formation as the lithology is a combination of carbonate and shale alternations, as shales could be considered as potential source rocks, whereas grainstones of tempestite facies have reservoir characteristics. Hence change of stratigraphic trap exploration is a scenario for these facies changes within the Pabdeh Formation. Furthermore, extensive fracturing in upper parts of the second sequence implies reservoir porosity development in these parts. Evidence of meteoric water flushing is implied in the third (last) sequence, leading to porosity development in this sequence.

## 681060 3-D visualisation of trapped hydrocarbons in carbonates from the pore scale: Exploring the residual hydrocarbon phase after secondary and tertiary flooding

*M. Knackstedt, M. Kumar, T. Senden and R. Sok*

At the conclusion of flooding in an oil- or gas-bearing carbonate reservoir, a significant fraction of the original hydrocarbon in-place remains in the swept region as trapped residual phase. In addition to the amount of trapped phase, its microscopic distribution within the pore space of a reservoir rock is important to gain a better understanding of recovery mechanisms and for the design and implementation of improved or enhanced recovery processes. Despite the importance of the pore scale structure and distribution of residual oil, little quantitative information is currently available. This study presents a robust method to obtain this critical information. Residual saturation visualization is undertaken in core material at the pore scale via microtomographic imaging. We utilize a new technique for imaging the pore-scale distribution of fluids in reservoir cores in three dimensions. The method allows reservoir core material to be imaged after different stages of flooding; for example after secondary and tertiary floods. Core flooding can also be performed under different wettability conditions, saturation states and flooding rates.

Although considerable attention has been paid to the subject of residual oil structure, the amount of quantitative experimental information on the structure of the residual oil phase in reservoir core material is limited. The detailed structure of the residual trapped phase is described. This information is correlated to pore structural

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information from the 3-D image data (pore geometry, connectivity), mineralogy and rock type. These results provide an important platform for the testing and calibration of pore scale modelling efforts for multiphase flow. This detailed pore scale information of the residual oil saturation is crucial to the design and implementation of improved recovery processes and can be related to conditions required for mobilization of residual oil. Oil recovery mechanisms are directly tested and the differences in the habitat of the residual fluids under different conditions are directly quantified.

## 706252 3-D imaging of residual saturation in carbonates; Exploring the role of wettability, rate and saturation state

*M. Knackstedt, T. Senden, M. Kumar and A. Sheppard*

At the conclusion of flooding in an oil- or gas-bearing carbonate reservoir, a significant fraction of the original hydrocarbon in place remains in the swept region as trapped residual phase. In addition to the amount of trapped phase, its microscopic distribution within the pore space of a reservoir rock is important to gain a better understanding of recovery mechanisms and for the design and implementation of improved or enhanced recovery processes. Despite the importance of the pore scale structure and distribution of residual oil, little quantitative information is currently available. In this study the residual saturation is directly visualized in core material at the pore scale in three dimensions. In particular, we utilize a new technique for imaging the pore-scale distribution of fluids in reservoir cores in 3-D; the method allows the same reservoir core material to be imaged under different wettability conditions, saturation states and flooding rates. A range of examples are given for waterflooding of reservoir carbonates. We observe a strong dependence of the residual hydrocarbon saturation and distribution on rate and wettability.

The detailed structure of the residual trapped phase is described. This information is correlated to pore structural information from the 3-D image data (pore geometry, connectivity), mineralogy and rock type as well as to wettability and flow conditions. These results provide an important platform for the testing, correlation and calibration of pore scale rock typing to multiphase flow properties. This detailed pore scale information of the residual oil saturation is crucial to the design and implementation of improved recovery processes and can be related to conditions required for mobilization of residual oil. Oil recovery mechanisms are directly tested and the differences in the habitat of the residual fluids under different conditions are directly quantified. The role of wettability is particularly studied. Crude oil drainage of simpler analogue materials are considered where flat mineral substrate have been incorporated. After aging and cleaning the planar slabs are removed and analyzed by surface sensitive techniques, in particular interferometric profilometry, to characterize the distribution of oil-wet and water-wet sub-regions. The results give some insight into the wettability conditions associated with waterflooding.

## 680946 Understanding and managing water advance in a heterogeneous carbonate reservoir: From integrated subsurface approach

*D.A. Lawrence, H.H. Mohamed, S. Elsembawy, Y. Yin, Y. Al Hammadi, M. Gashut and Y. Al Mehairi*

Rapid and uneven water advance is observed in heterogeneous platform-interior carbonate reservoirs in the south of a super-giant Middle East field, producing since the early 1960s. Crestal oil production is supported through peripheral water injectors typically 5–7 km from the producing area. Historical production imbalance has accentuated water movement in the south of the field, with wells ceasing to flow naturally even with relatively low water cut. A multidisciplinary approach has been used to understand controls on water encroachment. This involved integration of geology (core facies, correlation, reservoir properties), geophysics (seismic attributes, fault/fracture characterization), petrophysics (openhole & time-lapse cased hole logs) and reservoir engineering data (simulation models, production/injection).

Water advance is focused in certain areas of the field, and within limited stratigraphic layers. In particular, two prominent 'water fingers' are present within most reservoir units at the limit between the platform interior and thick prograding platform margin belt. Stratigraphic water fingering is controlled mainly by vertical variations in reservoir quality, particularly permeability within the five main reservoir units (named 1–5 from bottom to top). Water advance is less rapid in the lower two and the uppermost reservoir units (1, 2 and 5) which show interbedded stylolitic dense layers and lower matrix permeability (typically 1–10 md). Within units 3 and 4, water movement is more advanced and initially concentrated along super-high (Darcy-scale) permeability layers a few feet thick. Sequence-stratigraphic analysis calibrated with core confirms that such layers are associated with third- and fourth-order sequence boundaries, with partial cementation but preserving vuggy porosity. Within units 3 and 4, poorer reservoir quality facies (more cemented, coral-rich in unit 3) and non-reservoir carbonate mudstones (within unit 4) act as isolated local baffles to horizontal water movement. Controls on the location of the two prominent areal water fingers include faulting/fracturing, stratigraphic contrast between the platform margin and interior, and production/injection imbalance. An improved understanding of water movement is being used to predict future water breakthrough, refine infill drilling locations, plan future artificial lift requirements, design selective well completions and optimize field development.

## 728819 Mississippi Valley Type (MVT) mineralization in the Khuff C reservoirs, Saudi Arabia

*R.F. Lindsay*

Mississippi Valley Type (MVT) mineralization emplaced pyrite, sphalerite, galena, and gangue minerals, such as saddle (baroque) dolomite into the C carbonate of the Khuff Formation, of Late Permian age. In most cases small percentages of MVT mineralization had been identified in several Khuff reservoirs, both onshore and offshore. In one particular case MVT mineralization was represented by complete replacement of carbonate beds and consisted of multiple, thick layers of mineral deposits that contained moldic porosity. X-ray diffractometry confirmed the presence of pyrite, sphalerite, and galena.

In all cases, when MVT mineralization was identified it was located within the Khuff C carbonate immediately above the Khuff D evaporite. Major faults are thought to have delivered iron, zinc, and lead-rich fluids up-section from the basement or red beds that overlie the basement. Metal-rich fluids are considered to have derived sulfur by dissolution of the Khuff D evaporite and precipitated MVT minerals above the evaporite. This process essentially created a mixing zone to mix metals with sulfur as fluids moved up the fault zone in pulses, "squirt up a fault," during late Mesozoic and/or Tertiary deformation.

## 705727 Geochemical logging: A Middle East case study of a new logging tool

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While the traditional "Triple Combo" measurements remain a formation evaluation mainstay, in more complex environments many assumptions are made during the interpretation work. Lithology is interpreted from density, Pe, gamma-ray and neutron logs assisted by other sources of information such as cuttings and core analysis, however there are many limitations. Interpretation models can be refined with direct knowledge of elemental concentrations which are used to solve for complex mineralogy. For example, in a carbonate reservoir, a direct reading of magnesium elemental weight percentage provides a valuable measurement of dolomite volume. Similarly, sulphur fractional information provides knowledge of anhydrite distribution.

Geochemical logging provides a direct measurement of elemental concentrations and compliments the typical density, Pe, gamma-ray and neutron logs. The latest generation logging tool resolves a wide-range of elements including the traditionally more difficult-to-measure magnesium and aluminium elemental weight fractions. In this study we introduce a new geochemical elemental tool (GEM$^{tm}$) with examples taken from both siliciclastic and carbonate Middle-East reservoirs. One example from the important Permian age siliciclastic reservoir studied is an eolian dune and interdune facies, which contains varying volumes of diagenetic anhydrite cement, kaolinite and illite. The elemental concentration of silicon, titanium, sulphur and aluminium are inputs used to solve for these minerals in the lithology model. We demonstrate the accuracy of the elemental weight fraction from the logging tool results by comparison to Inductive Coupled Plasma Mass Spectroscopy (ICP-MS) and X-ray diffraction (XRD) measurements made from core. In addition results are presented of the mineralogy interpretation from the case study wells.

## 680699 Geological heterogeneity in the Wafra First Eocene Reservoir, Partitioned Neutral Zone (PNZ): Implications for steamflood development

*W.S. Meddaugh, N. Toomey, W. Dawson, W.T. Osterloh and D. Barge*

The Paleocene – Eocene First Eocene dolomite reservoir at Wafra Field in the PNZ (Saudi Arabia and Kuwait) is estimated to hold more than 10 billion barrels of 18–22 API, high sulfur oil. Current estimates suggest that only 5–10% of the oil originally in place (OOIP) may be produced during primary development. Consequently, steam flooding is being investigated as an appropriate secondary development option. A pilot consisting of single, very small 5-spot pattern with center injector has been used to demonstrate long term steam injectivity as well as to evaluate aspects of the reservoir response to steam injection. Critical to the economic success of the project will be a thorough understanding of the impact of both areal and vertical reservoir heterogeneity on steam migration. Analysis of temperature and petrophysical logs obtained in a temperature observation well located 35 feet from the injector have shown that a vertical barrier to steam migration exists approximately 80 feet above the base of the completions in the injector.

Two, relatively thick (5–10 feet), very low porosity and very low permeability evaporite-rich zones (mainly coalesced nodular to possibly bedded anhydrite with some gypsum) that were regarded as the most likely barriers prior to the start of steam injection did not act as barriers. Rather, an interval characterized by numerous thin, variously cemented (including celestite and native sulfur cements), exposure surfaces or hardgrounds seems to provide the vertical barrier. This zone is also characterized by generally low porosity and low permeability as well as very light oil stain. Detailed studies, including micro-permeameter measurements, thin section analysis, and quantitative mineralogical studies, are being used to further characterize the steam barrier interval. The geological and stratigraphic assessments of heterogeneity are supplemented by a history-matched thermal simulation model that suggests that the evaporite-rich zones may have acted as short term baffles but that the "ultimate" barrier is coincident with the interval characterized by abundant exposure surfaces or hardgrounds.

## 680841 The impact of geostatistical model parameters from fluid flow: Detailed modeling of the large scale steamflood pilot (LSP) area, Wafra First Eocene Reservoir, Partitioned Neutral Zone (PNZ)

*W.S. Meddaugh, H. Tang and N. Toomey*

The First Eocene reservoir at Wafra Field in the PNZ is a Paleocene – Eocene age dolomite reservoir. The 40-acre, LSP steamflood project consists of 56 new wells (producers, injectors, and temperature observation wells), of which four are cored through the producing interval. The project area also includes four older wells, one of which was cored. Semivariogram models computed from the LSP wells (25–100 m well spacing) have correlation lengths on the order of 200–300 m whereas previous full field studies determined correlation lengths of 1500–2000 m using the primary development wells (500 m typical spacing). To test the impact of semivariogram model parameters and data density on fluid flow response five sets of static reservoir models were built. The fine scale static models (5 m areal grids, 4.5 million total cells) were simulated without up-scaling using 3-D streamline simulation. The dynamic scenarios selected were designed to reduce the noise of well distance, sweep direction and material balance error on the results. Analysis of variance (ANOVA) shows, with above 95% confidence, that models built using short semivariogram ranges have significantly higher recovery than models built using large semivariogram range. The conditioning well density does not significantly impact recovery.

The effect of areal grid size was also examined. Static models were generated using 10 m, 20 m, and 40 m areal grid sizes and fluid flow response investigated using 3-D streamline simulation. The results suggest that grid size may also significantly impact recovery as models generated using the 40 m grid size gave more optimistic results compared to models generated using the smaller areal grid sizes.

## 680846 Effects of dolomitization on reservoir quality of Sarvak Formation (Cretaceous) in one of the giant oil fields in southwest Iran

*R. Moussavi-Harami, A. Mahboubi, M. Alahabadi and A. Adhamian*

The Albian – Cenomanian Sarvak Formation is one of the major oil-producing units in the Zagros Basin. In the studied wells, the formation is about 637 meters thick and can be divided into: (1) lower part (257 m thick) composed of interbedded fine grained limestone with pelagic fauna and shale; and (2) upper part (380 m thick) consisting of dolomitized neritic limestones with interbedded fine grained limestones. Based on petrographic (207 thin-sections of cutting) and petrophysical studies of well logs, the effects of dolomitization on reservoir characteristics of the Sarvak Formation have been evaluated. According to crystal size and shape, as well as presence of dolomite in different lithofacies, three types of dolomite have been identified. Type one is fine grained (5–60 microns) that has formed at the early stage. Type two is medium grained (60–250 microns) and type three is coarse grained (250–500 microns). Both of these formed during burial at a later stage of diagenesis. Based on petrography and well log analysis, the second type dolomite has increased the quality (porosity and permeability) of the reservoir rocks in this field.

## 727494 Integrated reservoir management leads to improved productivity from Khuff gas reservoir of Awali Field, Bahrain

*C. Murty, S.S. Abdulla and E. Alowainati*

The Awali Field is a mature asset containing several oil and gas reservoirs. The bulk of gas reserves are located in Khuff and pre-Khuff (Unayzah) reservoirs. The Khuff is a carbonate reservoir that is subdivided into four units: K0, K1, K2 and K3. These gas reserves are vital for the country because they represent the main domestic energy supply. All the subunits are highly productive except K3 where the production is marginal as it is derived mainly from the fractures. An integrated reservoir monitoring is in place to improve the asset management of this critical resource. This includes: (1) updating reservoir description using the data from core analysis; (2) ensuring proper depletion by monitoring the reservoir pressure; (3) reviewing the production performance from various units; (4) recording the deliverability of wells periodically; (5) revising the perforation inter-vals based on the rock typing; and (6) monitoring the movement of the gas/water contact.

A surveillance program is implemented yearly to acquire data from the reservoirs. The deliverability of the wells is monitored using the SCADA system. A study on the system pressure reduction was undertaken which indicated that the productivity can be enhanced by reducing the well-head tubing pressure. Accordingly the gas dehydration units are being modified to handle production with low well-head pressures. The reservoir perforation policy is also revised using the study which helped in improving the productivity. This study discusses how the integrated study helped in providing a good framework needed to assess the best ways to improve the exploitation of the gas reserves.

## 695343 Thermal simulation for a shallow limestone: Rubble reservoir in Awali Field, Bahrain

*C.R. Murty, A.E. Al-Muftah and K. Kumar*

Rubble Limestone is the descriptive name given to a massive limestone unit of the Mishrif Formation, mid Cretaceous in age. The zone consists of two layers which are eroded in the crestal part of the structure. Large volumes of oil are trapped against the blue shale at the up structure. The zone has both heavy and light oil. The amount of heavy oil is estimated to be 90% of the initial oil-in-place. Currently only light oil is being produced. This study highlights the studies to evaluate heavy oil production potential. Two separate studies were carried out, the first was to describe and characterize Rubble in order to map the light and heavy oil and the water-bearing layers. Geostatistical methods were used to populate the 3-D model of the reservoir with porosity and permeability values. After obtaining an estimate of the areas of heavy and light oil, a fresh study was initiated to review and evaluate the heavy oil prospect and to prepare a suitable thermal enhanced oil recovery (EOR) pilot plan for the heavy oil recovery. The study included numerical modeling and simulation of a pilot area, identification of the suitable EOR process and design of the pilot.

The study indicated that the reservoir has too low matrix permeability and very small fracture volumes to allow steam chamber formation. Steam-assisted gravity drainage (SAGD) mechanism was therefore found not efficient for this reservoir. Cyclic steam stimulation (CSS) has been simulated using two wells in the pilot area and found attractive. Cold production from six different horizontal wells were simulated and tested. They indicated that cold production followed by CSS will be efficient to recover the heavy oil. The presentation will describe the results of the study, which led to drilling of the horizontal pilot well for cold production to be followed by CSS thermal process.

## 680932 Conceptual and numerical modeling of fracture-related high temperature dolomite: Implications for reservoir characterization

*F.H. Nader, J. Daniel, O. Lerat and B. Doligez*

Classical diagenesis studies make use of a wide range of analytical techniques in order to suggest conceptual models that explain specific, relatively time-framed, diagenetic processes and their impacts on reservoirs. Still, these models are qualitative and do not yield "real" data for direct use by reservoir engineers for rock-typing and geo-modeling. This contribution provides new insights into numerical modeling of dolomitization following two approaches (geostatistical and geochemical transport reactive), and attempts to express the conceptual models of hydrothermal dolomitization which is known to have affected reservoirs in the Middle East, in more quantitative terms.

A 3-D geostatistical model representing the Ranero dolomitized Cretaceous platform carbonates was constructed, covering an area of 5x2 km and a depth of 2 km. It is based on interpretation of aerial photographs, geological and topographic maps, as well as field observations. The resulting 3-D block included the stratigraphical units, fractures and the dolomite bodies. Geostatistical simulations succeeded in reproducing the dolomitized pattern. A relationship was set to restrict the presence of dolostones to the fractures at depth. A 2-D geochemical transport reactive model was built to represent a high temperature dolomite (HTD) front (ca. 350 m long; cells: 5x1 m) in the Marjaba Jurassic platform carbonates. The nature of the dolomitizing fluid was constrained based on results of fluid inclusions and crush-leach analyses. Two aquifer analogues for the end-members of the mixed dolomitized fluids were chosen according to their similar sedimentological character, mineralogical compositions and ambient temperatures to the expected sources of evaporative marine-related waters and hydrothermal fluids.

The geostatistical model helped in illustrating the relationships between the hydrothermal dolomite distribution and the fracture pattern. Numerical reactive transport simulations are valuable not only for predicting hydrothermal dolomite texture (porosity/permeability) distribution but also for validating the prescribed dolomitization model. This study provides means to predict fracture-related HTD distribution and related evolved reservoir properties, thereby achieving better reservoir characterization.

## 726630 Reservoir permeability estimation using neural network and geostatistical approaches

*K. Najafzadeh, M.A. Riahi and S. SeyedAli*

Estimating permeability from well-log data in uncored borehole intervals is an important and difficult task. On the other hand, direct prediction of reservoir permeability from seismic data is often supposed impossible due to resolution limitations of seismic data and hydraulic nature of permeability. In many cases reservoir permeability estimation is restricted to core scale and wellbore proximity. Commonly, permeability is estimated from various well-log curves using empirical relationships or multiple linear regression (MLR), but it seems that artificial neural network (ANN) produces a more reliable response related to reservoir permeability estimation. The aim of this article is to build a reliable structural model of study area from seismic data, then a back propagation ANN is used for reservoir permeability estimation in uncored intervals. Also geostatistical approaches are used for permeability estimation. At last validity of methods has been checked by cross validation and a comparison between methods has been made.

## 680448 Jurassic carbonate tight gas in North Kuwait: Exploration through initial production

*S.R. Narhari, Q. Dashti, N.H. Al-Ajmi, R. Al-Mayyas, K. Al-Ateeqi and S. Chakraborty*

Kuwait Oil Company (KOC), as part of the strategy to meet the domestic gas demand, is currently developing the six North Kuwait Jurassic age tight gas reservoirs. Until the early 1990s the majority of the exploration and production activity in Kuwait was focused on the shallow conventional Cretaceous targets. A paradigm shift in exploration activity with focus on unconventional reservoirs, driven by detailed seismic studies and revised depositional models, led to the discovery of six North Kuwait Jurassic gas fields. These reservoirs, Najmah-Sarjelu and Middle Marrat, are characterized by low porosity (average < 5 pu), low permeability (average < 0.1 mD) and in deep (> 13,500 ft depth) HP/HT (average 11,000 psi/280°F) sour conditions. Sub-vertical natural fractures are the main contributors for production for the Najmah-Sarjelu reservoir. Though dolomitization improved reservoir characteristics of the Middle Marrat in part of the area, natural fractures play a dominant role in aiding production from this reservoir. A dual-porosity geocellular model, encompassing this large area (ca. 1,800 sq km) having large gross reservoir thickness (ca. 2,200 ft), with limited 39 well control is built to understand the hydrocarbon in-place (HCIP) and as an input for the simulation model. A detailed interpretation of log, core, and seismic data helped in refining the depositional model. The discrete fracture network (DFN) models are constrained by seismic attributes for realistic fracture population in the inter-well space. This study presents the journey from exploration to early production with focus on challenges being faced and the mitigation strategies adopted in modeling and developing these fields.

## 681224 Understanding fractures through seismic data: North Kuwait case study

*S.R. Narhari, A. Al-Kandari, V. Kidambi, S. Al-Ashwak, B. Al-Qadeeri and C. Pattnaik*

Understanding fracture corridors is the primary driver for successful development of fractured carbonate reservoirs. This assumes further significance if the carbonate reservoir is characterized by very low porosity and permeability; producibility of the reservoir is purely dependent on the presence of natural fractures. Distribution and type of natural fractures is a function of palaeo and present-day stress, structural elements, regional tectonics and diagenetic history. Direct detection of fractures is below the resolution of conventional seismic data. However, through a combination of seismic-derived attributes integrated with well data, it is possible to better understand the distribution of fracture swarms.

Kuwait Oil Company (KOC) is currently engaged in an early phase of development of a tight fractured carbonate Jurassic gas play in North Kuwait. Considering the limited well control, field development is heavily reliant on seismic data for fracture characterization. This study presents our current understanding of the relationship between fractures observed in the well data and structures, faults and lineaments interpreted on seismic data. In addition to conventional seismic analysis a suite of seismic attributes including dip, coherence, edge and 3-D volume curvature were used for mapping structures, faults and minor lineaments. Well-wise and field-wise analysis of relationships between seismic derived attribute-pattern and fracture orientation was established. The understanding between these two different sets of data has helped in locating potential zones of sweet spots for placing successful delineation and development wells. These seismic attribute volumes were also used as soft constraint for building the discrete fracture network (DFN) model for populating the fracture network in the reservoir model. The data presented in this study are from the Raudhatain, Sabriyah and North West Raudhatain (NWRA) fields for the Najmah-Sarjelu part of the Jurassic section.

## 680856 Modeling pore pressure profiles in carbonates

*S. O'Connor, R. Swarbrick, S. Jenkins, S. Green and P. Clegg*

Carbonate reservoirs are the targets of many drilling programs around the world. In other cases, carbonate rocks need to be drilled through to reach deeper reservoirs. Understanding the pressure regimes in these carbonates is vital both for safe drilling and for reducing uncertainty in actual reservoir pressures. As there is no relationship between effective stress and porosity/velocity in carbonates, approaches based on changes in porosity using seismic velocity and/or log data such as sonic and resistivity measurements will give false magnitudes of overpressure in these carbonate units. Therefore another approach is required, one based on understanding the mechanisms of pressure generation and build-up in a basin (a geological approach), "calibrated" using available (although often rare) direct pressure measurements in permeable horizons within these units, coupled with shale-based prediction techniques in any clastic intervals above and below the carbonates.

A geological approach based on lithology can be used to predict pressure in carbonates. Data needed includes porosity and permeability characteristics of the carbonates, where low-permeability marls and wackestones produce different pressure profiles in comparison with high-energy, more permeable, reefal carbonates such as grainstones and packstones. The latter group of carbonates may be sufficiently well-plumbed to allow hydrodynamic flow, leading to hydrocarbon/water contacts, a feature of some of the larger Middle East oil and gas fields. A significant control on the internal pressure regime of carbonates are the pressures of any associated clastics, both above and below the carbonates; that is carbonates themselves do not normally generate overpressure but have pressure transition zones that reflect the pressures above and below. The shape of the transition zone relates to the carbonate permeability whereby high permeability pressures are hydrostat parallel and low permeability carbonates have pressure transition zones coupling top and base pressures. Using case study material from the North Sea Chalks and SE Asia Limestones, as well as from Middle East analogues, we will illustrate how a combination of these techniques can be used to model the pore pressure profiles better through and within carbonates.

## 668262 Detailed compositional modeling of gas injection pilot in giant carbonate reservoir in the Middle East

*T.A. Obeida, A. Gibson, B. Baruah and H. Al Hashemi*

The objective of this presentation is to address the main challenges that have been encountered in the simulation study when using local grid refine (LGR) within upscaled models. The challenges are mainly due to the unreliability of populating the fine grids with reservoir properties and attributes. Dynamic modeling of a pilot is an important task to predict fluid flow and reservoir behavior which is a major step of pilot design. Dynamic models usually have many limitations when it comes to geological description due to upscaling of fine-grid static model. Using LGR to cover the pilot area within coarse dynamic model also would not enhance reservoir description in the pilot area as a result of the difficulty of attributes validation. This work aimed to provide an improved method for proper simulation in order to optimize the design of the pilot injector, borehole location and length, in addition to plan an efficient reservoir monitoring program including an optimized well data gathering with sponge coring for defining the remaining oil saturation.

To overcome these limitations, the proposed method introduces fine scale LGR covering the pilot area then exports the LGR to the static model with the same layering scheme of the static model and then imports the LGR with fine layering including the properties of geological model into the dynamic sector model. This process will ensure better quality match of the actual TDTs and RSTs, fine layering saturation profiles when compared with the sector model results. Sector model with 160 layers was re-history matched to ensure consistency. Prediction cases were studied to optimize well location in order to convert the existing inverted five-spot pattern into line-drive. Saturation maps and profiles were generated to predict the breakthrough time for each observer and utilized to design the future pilot monitoring program.

## 705599 Study of open fractures in a permeable rock matrix using a two phase numerical flow model and its effect from production

*I. Oraki and B. Habibnia*

The presence of open fractures in a permeable matrix generates highly heterogeneous permeability fields which have a large impact on the relative flow of oil and water. This results in highly variable velocities which in turn generates complex oil-water fronts and strongly heterogeneous water saturation fields. Such conditions make prediction of reservoir behaviour difficult and efficient recovery problematic. One of the best known effects is early water breakthrough at wells due to the preferential flow of water along a connected fracture system. In the present study the effects of open fractures on the flow of oil and water are investigated using a two-phase numerical flow model with some simple and simulated and natural fractures patterns. The results are used to investigate the nature of 'pseudo curves' (relative permeability curves for volumes of heterogeneous rock) in the case of fractured permeable rocks. And we will get an important result that increasing fracture aperture beyond a critical value does not significantly alter the pseudo relative permeability curves.

## 705376 Wavelet transform modulus maxima lines analysis of seismic data for delineating reservoir fluids

*S. Ouadfeul and L. Aliouane*

The main goal of the proposed idea is to use the wavelet transform modulus maxima lines (WTMM) method to delineate reservoir fluids. First a seismic seismogram is generated using the convolution of the Ricker wavelet with the reflectivity function calculated from the measured sonic and density well logs data. Obtained seismogram is analyzed by the WTMM in order to calculate the singularities spectrum based on the direct Legendre transform of the spectrum of exponents. Application of this technique at the real data of a borehole located in the Algerian Sahara is realized. Thus singularities spectrum is estimated at corresponding depth of the following fluid types: gas, oil, water, gas-oil and oil-water. Consequently, the obtained results allow taking a decision about the fluid nature contained in the reservoir rocks' pores. We have applied the proposed technique at two other boreholes, obtained results demonstrate that the wavelet transform modulus maxima lines technique can give more idea about hydrocarbon nature and can enhance reservoir characterization.

## 705380 3-D seismic AVO data established by the wavelet transform modulus maxima lines to characterize reservoirs' heterogeneities in the 2-D domain

*S. Ouadfeul and L. Aliouane*

The main goal of this study is to establish reservoirs' media heterogeneities by the wavelet transform modulus maxima lines. First we gathered amplitude *versus* offsets AVO amplitudes at the top of the reservoir and we calculate the 2-D wavelet transform after we calculate its maxima and we estimate the Holder exponent at each one. Variation of this coefficient can give more information about the variation of lithology and fluid nature at any direction. Application of this idea at synthetic 2-D seismic model shows that application on real seismic AVO data and its attributes can give more ideas about reservoirs' heterogeneities.

## 680963 Integrated dolomite characterization of a deep Jurassic formation in Minagish Field, Kuwait: A case study

*G.S. Padhy, B. Kumar, E.A. Al-Mayyas, N. Verma and F.M. Fawzy*

The Jurassic Marrat Formation in Minagish Field contains a deep, over-pressured, tight carbonate reservoir with light oil production history of 24 years. Nearly 16 deep wells penetrate this reservoir of which 12 were completed as naturally flowing producers. Petrophysical characterizations of this complex carbonate reservoir is a challenging task due to constraints imposed by large well spacing, small well bore diameter, use of oil-based mud, HP-HT coupled with a $H_2S$ environment. Reservoir characterization away from wellbore is equally challenging due to inadequate resolution of 3-D seismic data at depths exceeding 11,000 feet. Understanding the role of both primary depositional and secondary diagenetic processes in porosity development through integrated reservoir characterization assumes great significance in such circumstances.

This study documents efforts to define an accurate mineral model for probabilistic petrophysical analysis especially dolomite characterization, which plays an important role in reservoir development being less susceptible to porosity reduction under high overburden pressures and deep settings. As evident from core analysis results (porosity and permeability), dolomitization plays a significant role in increasing the storage capacity. So quantification of dolomite is highly necessary, not only to understand reservoir rock quality, but also as a key input into the static and dynamic reservoir modeling. However, the same is difficult in the absence of special logs like neutron capture spectroscopy data which provides a better solution. Conventional open hole logs (density, neutron and sonic) have their own limitations and uncertainty involved due to several factors such as: barite mud effect, oil base mud invasion, complex lithology, sensitivity etc. and hence alone cannot be used with full confidence for a complete characterization. Notwithstanding this limitation, at this end, an attempt was made to solve this dolomite volume and build a good mineralogical model through an integrated workflow approach where information from high resolution sequence stratigraphy, core and electrolog based rock typing, core analysis and the available conventional logs were used. This integrated approach was followed for a few key wells with all inputs to build the probabilistic multi-mineral model, with reasonable confidence and define the parameters which were later applied effectively for all other wells in the field for successful dolomite mapping and identification of the zones of interest. The results were further incorporated in the static reservoir modeling providing a new dimension to the reservoir characterization (reported elsewhere). This approach is planned to be validated and calibrated with neutron capture spectroscopy data in the future wells.

## 681327 Integrated formation evaluation of high-pressure, high-temperature tight reservoirs: A case study from West Kuwait

*A. Rabie, R. Husain, A.H. Sajer, Al-Mukhaizeem and A. Al-Fares*

Triassic reservoirs in the western part of Kuwait have flowed gas and condensates on testing. These reservoirs are characterized by a complex suite of rocks consisting of dolostones, limestones, anhydrites, shales and halite. Conventional reservoir quality is poor as porosity and permeability are negatively affected by multiple diagenetic events and can easily go undetected

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by most logging tools which are mainly designed for conventional reservoirs. Also these occur at greater depths which require high pressure high temperature drilling, small borehole design, use of oil based mud and specialized cementing practices. As a result the availability of the full suite of logs is limited and the reservoir facies are difficult to identify and evaluate quantitatively.

Additionally often salt plugging in both the surface test system and the downhole tubular impedes the production and masks the interpretation of the gas zone. It was difficult to determine the true rates from the well due to the high water cut and salt plugging. It is necessary to investigate the source of water production and causes of salt plugging and also necessary to determine the correct gas zone interval for next re-perforation.

Innovative and integrated workflows involving state-of-the-art technologies and incorporating wireline logs, core, gas chromatography, fracture, thin section petrography, well test and mud logging data have been employed for identification and evaluation of these reservoirs. These practices have been instrumental in effective exploration and evaluation of tight, HPHT reservoirs and highlight the need for synergistic workflows that need to be updated on a continuous basis.

## 680474 A genetic algorithms approach for prediction of compressional and shear wave velocities from petrophysical data: Example from Sarvak carbonate reservoir, Iran

*M. Rajabi, E. Gholampour Ahangar, S. Mousavi and I. Moatazedian*

Compressional and shear wave velocities (Vp and Vs) are important reservoir characteristics which have many applications in petrophysical, geophysical and geomechanical studies. These parameters (especially Vs) are directly obtained from core analysis in the laboratory or by dipole sonic imager (DSI) tools. Since the laboratory methods are very expensive and time consuming, and the conventional sonic tools cannot measure Vs, studies are led to find new methods for wave velocity estimation. Many researchers have tried to predict Vs from well-log data. Most of these studies have been carried out for Vs estimation in sandstone reservoirs. Since carbonate rocks are considered as the major parts of the world's oil and gas reservoirs there is a need to study more about Vs and Vp estimation in these types of reservoirs. In this study Vp and Vs were predicted from well log data using genetic algorithms (GAs) technique in an Iranian carbonate reservoir (Sarvak Formation). A total of 3,030 data points of two wells from Sarvak carbonate reservoir which have Vp, Vs and conventional well log data were used. These data were divided into two parts, one part used for constructing GAs models and the other part used for models testing. The measured mean squared error of predicted Vp and Vs in the test data was 0.0296 and 0.0153 respectively. Prediction in carbonate rocks is difficult because of diagenetic processes; however, GAs give reliable results. Therefore using this methodology Vp and Vs can be obtained for Sarvak Formation in other wells of Abadan Plain, which have no Vp and Vs data.

## 705954 Comparison of patterns of permeability anisotropy distributions in Jurassic and Cretaceous carbonate reservoirs

*A. Sahin and A.Z. Ali*

Permeability measurements in most reservoirs display strong dependency on the direction. Therefore, it is essential to determine permeability variations in different directions within the reservoirs. Such variation is generally incorporated into engineering applications as the square root of the ratio of the horizontal to vertical permeability, a parameter known as the anisotropy ratio. This ratio may vary from one zone to another and even from one layer to another in the reservoir sequence. The pattern of variation of this ratio provides valuable information about flow behavior within the reservoir. Based on the whole core data from several vertical wells, permeability anisotropy distributions in three carbonate reservoirs, including an Upper Jurassic, and two Cretaceous (lower and middle) reservoirs from the Arabian Gulf region, were determined. The open-hole log data and the whole core permeability measurements were plotted together with the calculated anisotropy ratio values to aid interpretation. Such plots were generated for each well from each reservoir providing basis for the comparison of anisotropy ratios with the corresponding porosity and permeability values.

The results revealed that the anisotropy ratio distributions closely follow the corresponding distributions of permeability. The values of anisotropy ratio vary considerably from reservoir to reservoir. Upper Jurassic reservoir revealed relatively higher values of anisotropy ratios as compared with Cretaceous reservoirs. Considerable variations have also been observed within each reservoir. In Upper Jurassic reservoir, some correlation has been observed between anisotropy ratios and porosity values, indicating close relationship between anisotropy ratios and lithology. In Cretaceous reservoirs, on the other hand, no obvious relationship between anisotropy ratios and lithology has been depicted. In all cases, it has also been observed that very high values of the anisotropy ratios are generally due to unusually low vertical permeability measurements recorded in compact and undisturbed muddy intervals acting as the barriers to the vertical flow.

## 654497 Characterization of Ahmadi Reservoir of Awali Field, Bahrain, with DFN model using transient well testing

*A.A. Shaban, T. Le Maux and L. Ghilardini*

The Ab Formation of the Ahmadi Group in is one of the most difficult reservoirs to produce in Awali Field. It has tight matrix with low permeability and complex fracture system making it difficult to produce. Hence, the understanding of such fractured systems is essential for modeling and improving the production and ultimate recovery from this reservoir. To help with that, discrete fractured network (DFN) modeling has been used to characterize this fractured reservoir. If integrated with other data from the field, DFN can provide more representative fractured models. Transient pressure welltesting, a widely known applied reservoir characterization technique, can be used to validate the suggested DFN models.

This study presents the work that incorporates a sensitivity analysis study used to test and investigate the parameters that have a direct effect on the curve signature of the transient pressure welltest analysis and their interpretations. Different customized DFN models were built and simulated to obtain the pressure measurements under different scenarios. Various pressure derivative curves were generated and compared to investigate the sensitivity of fracture parameters on the signature responses. The study concludes with actual field cases from the Ab fractured reservoir.

## 696514 Role of artificial intelligence in different stages from advanced petrophysical reservoir characterization process: Case study of Iranian carbonate reservoirs

*M. Shahvar, R. Kharrat and M. Matin*

Reservoir characterization is a critical stage in simulation of oil and gas reservoirs. An appropriate characterization yields to a robust simulation model that can enhance the production and reservoir management, but characterization of carbonate reservoirs has always been faced with difficulties. The reason is due to the heterogeneity that exits in reservoirs of this type. Heterogeneity causes complexity in the relationship between different petrophysical parameters and therefore simple mathematical equations would not be helpful anymore. This problem can be observed in prediction processes such as rock type and permeability prediction, water saturation estimation and relative permeability prediction. Artificial intelligence has been used as a solution to this challenge in the last decade. The role of this mathematical approach has become so important that ignoring it in a reservoir characterization is impossible. In this comprehensive case study, using conventional core and wireline log data, application of artificial intelligence technology is investigated in different stages of petrophysical characterization of two heterogeneous carbonate reservoirs. These reservoirs are located in two giant oil fields in southwest Iran.

All the possible artificial intelligence techniques such as artificial neural networks and fuzzy logic that can be useful in predicting the static and dynamic properties of the reservoir rocks are considered. Porosity, absolute permeability, relative permeability, rock types and saturation of the reservoirs under study are the parameters that are selected to be estimated by artificial intelligence methods. Among these parameters, models of porosity, absolute permeability and rock types (flow zone index) are generated by both artificial neural networks and fuzzy logic, using wireline logs data as inputs, and then the models are compared with the results of applying multiple regressions. Saturation and relative permeability also are predicted by artificial neural networks and multiple regressions in which the input data are other petrophysical properties.

Obtained results from the models generated by artificial intelligence are more accurate and have more correspondence with core-derived data with respect to the results of applying multiple regressions. This fact shows the importance of implementing artificial intelligence techniques in modern reservoir characterizations.

## 696559 A new approach to predict relative permeability by artificial neural networks using the concept of hydraulic units: Case study from Iranian carbonate reservoir

*M. Shahvar and R. Kharrat*

Relative permeability is an important petrophysical parameter that plays a critical role in simulating oil reservoirs. Determination of fluid distribution and residual saturation, characterization of two-phase flow in porous rocks and predicting the future reservoir performance, are just some of the fields for which relative permeability has application. Since laboratory measurements of relative permeability do not provide accurate values for the reservoir scale, and also are expensive and time consuming, many efforts have been done to find a way to predict relative permeability.

In this study, relative permeability is considered as a parameter that can be used to distinguish between different hydraulic units. Each hydraulic unit has its own set of relative permeability curves that usually are similar within one unit and are different from the set of other units. This fact is used to differentiate the prediction models of relative permeability based on the hydraulic units. To accomplish this, the flow zone index (FZI) approach is used to determine the hydraulic units of a heterogeneous carbonate reservoir of a giant Iranian oil field. Then the relationship between major units that constitutes most of the reservoir rock and relative permeability data is validated using relative permeability curves. Capillary pressure curves are also used as a tool to investigate the number of units defined by the FZI approach. To build the synthetic models of relative permeability hydraulic unit number 10 of the reservoir under study is selected. Artificial neural networks with proven application to relative permeability prediction are considered to generate a prediction model. Besides porosity, end point saturations and other rock and fluid properties, some functional links are also used as inputs for the model. Back propagation is the algorithm applied in this study to minimize the error. After training and testing the networks, some data associated with unit 10 that were not introduced to the network while training, were used to validate the network performance. The results show a good correlation between predicted relative permeability and measured ones. This strategy is applied for both the water and oil relative permeability predictions and the results are satisfactory. Using this approach, each hydraulic unit of a reservoir rock will have its own relative permeability model, enhancing the relative permeability imaging of the whole reservoir rock.

## 705325 Depositional and facies controls on infiltrated/inherited clay coatings: Unayzah sandstones, Saudi Arabia

*S. Shammari, S. Franks and O.M. Soliman*

Clay coatings on detrital quartz grains inhibit precipitation of burial diagenetic quartz overgrowths and help preserve porosity and permeability in Unayzah sandstones. These clay coatings are physically emplaced, not neoformed (authigenic) clay coats such as fibrous illite or radial chlorite. Understanding the depositional and facies controls on these clay coatings is necessary to predict reservoir quality in the Unayzah sandstones. Petrographic and scanning electron microscope (SEM) analysis of sandstones from different depositional settings and stratigraphic units within the Unayzah were made to investigate the relationships between facies and the presence of grain coatings.

Grain coatings are found in all investigated depositional environments: eolian, fluvial, lacustrine, glacial diamictite, and estuarine settings. These coatings are especially abundant in sandstones associated with clay-rich paleosols. They are presently composed of illite and/or chlorite, but they may have had precursor clay minerals prior to burial diagenesis (e.g. smectite, sepiolite, or palygorskite). The relative amounts of clay coatings depend not only on the type of depositional environment, but also on the stratigraphic unit within which the environment resides. This is interpreted to be a function of changing paleoclimates during deposition of the Unayzah. For example, in the fluvial setting, the percentage of clay coatings in the relatively warm fluvial systems in the upper part of the Unayzah A is much higher than in the cold lower fluvial systems of the Unayzah C.

Moreover, this study shows that the presence of clay coatings is grain-size dependent. For a given depositional setting (e.g. fluvial environment and its sub-environments), there is a direct relationship between the mean grain size of sandstones and the average percentage of coated grains in all samples of this facies. In finer-grained facies, as in a distal sheet flood, more clay coatings (ca. 90%) occur. In coarser-grained facies, as in a fluvial channel, fewer grain coatings (ca. 50%) occur.

Chlorite is the dominant clay coating in eolian settings, especially associated with coarser eolian grains in dune and sand sheet sub-environments recognized in the upper part of the Unayzah (Unayzah A). Also, in this unit, grains deposited in fluvial settings may be coated with illite or chlorite. In estuarine, and fluvially dominated estuarine deposits (of the Basal Khuff Clastics), illite is the dominant clay coating. Both chlorites and illites are present (with different percentages) in the relatively finer grains deposited in floodplain/playa and interdune/distal sheet flood sub-environments of the Unayzah A and B units.

In summary, depositional environment, paleoclimate, and grain size are all factors in the genesis of clay coatings. Some clay coatings formed in place by pedogenesis (soil-forming processes), and "inherited" clay coatings on grains transported by eolian (and fluvial) processes may have originally formed in pedogenic environments. Airborne dust may also be a factor in the genesis of clay coats as it would help explain the presence of clay coats in all environments, but presently we have no direct evidence to test this hypothesis.

## 680842 Nodular chert occurrences in the Upper Jurassic Diyab Formation, Abu Dhabi, United Arab Emirates

*A. Siddiqui and M. Kaneko*

The Upper Jurassic Diyab Formation was deposited during a marine transgression resulting from regional subsidence. The Diyab Formation consists of argillaceous lime mudstones and wackestones that change laterally eastward into peloidal packstones, grainstones, and dolomitic packstones. In Abu Dhabi, the Diyab Formation is subdivided into three informal members: lower, middle, and upper based on the lithology and gamma-ray signatures. Diagenetic silica occurrences in the Diyab intervals have been identified by conducting visual inspection of cores, as well as petrographic analyses on some core samples. Silicification of carbonate host rock involves the precipitation of silica in the form of pore-filling silica cement as well as the replacement of carbonate by chert. Early mechanical compaction and sediment dewatering played an important role in the siliceous skeletal particles' dissolution, migration of silica rich fluids and the consequent precipitation of chert. Nodular chert is the most common diagenetic silica form observed in the Diyab Formation, whereas selective replacements and silica cement within carbonate samples are also observed.

Most occurrences of nodular chert are encountered near and inside dolomitic layers of the upper zone of the Diyab reservoir. Chert in carbonate rocks is generally known to be of biogenic origin. However, within the Diyab reservoir their occurrence is closely associated with the infiltrated brine, which also caused dolomitization in the carbonate rocks. These minor chert replacements have not significantly affected reservoir quality, but their recognition is important in calibration of wireline log responses for lithology. Microfractures also developed within the nodules due to the brittle nature of chert and these fractures may also aid in the fluid transport within the reservoir.

## 680594 Quality fracture network assessment for IOR feasibility: Case study in fractured carbonate rock, United Arab Emirates

*M. Sirat and D. Kuehn*

The implementation of the improved oil recovery (IOR) methods to increment the recovery factor in naturally fractured reservoirs is often expensive and time-consuming. Therefore a detailed reservoir quality assessment of key attributes of the fracture network in an analogue outcrop of carbonate rocks will help unravel its impact on the IOR pilot. Detailed fracture analysis was conducted on collected data from the Eocene – Miocene outcrop exposure of the fractured carbonate rocks in Jabal Hafit Anticline in Abu Dhabi. This study aims to assess the effect of critical fracture parameters such as geometry, interconnectivity, density, aperture, size, mechanical layering and ambient stress condition on fractures openness and reactivation mechanisms. It also introduces a method to estimate the seal potential ratio based on aperture measurements of representative fractures chosen over areas of different structural settings in Hafit structure.

Results indicate that there are two fracture systems; an older E-W trending and a younger N-S striking system, which have been formed in at least two different tectonic settings from Cretaceous to present. Each of these systems is divided into three vertical to sub-vertical fracture sets; an extensional (joints) and two conjugate shear sets (faults). Some of these extensional fractures and faults are partially or entirely sealed by calcite or clay gouge filling. Fracture density shows a log-normal relationship with bed thickness, which increases in dolomitized limestone facies, in the crestal area and in the vicinity of pre-existing faults and shear zones. Fracture size is inevitably constrained by the outcrops exposure. Fractures aperture varied between 0.5 to more than 30 cm, depending on fracture geometries, positions in the anticline and lithology, and calcite fillings.

We consider that only fractures of the second system is preferred for fluid flow along corridors that are held opened by the current N-S to NE-SW ambient stresses unless locally sealed by clay or calcite mineralization. However, at the vicinity of a fault, the estimation of fractures openness depends on the fault geometry and the associated in-place stress tensors around the fault. Fractures connectivity is controlled by individual fracture set geometry together with the current in-place stress. Riedle and diffused fractures connect those opened fractures and faults of this system together with the bedding planes giving rise to a dual-permeability reservoir.

## 680063 Estimation of reservoir properties from seismic attributes and well log data using artificial neural networks

*M. Sitouah, G. Korvin, A. Al-Shuhail, O.M. Abdullatif, A. Abdulraheem and A. Zerguine*

Porosity and permeability are key factors to build a 3-D geological model for a reservoir. The best method to get these properties would be to measure them on core samples in the laboratory. However, this method is costly and time consuming, and usually only a few out of all wells are cored and even then only a small portion of the well. To fill the gap in the vertical scale, geologists generally use a statistical approach, such as linear or non-linear multiple regressions to correlate reservoir properties with the continuously recorded well log data. Recently, geoscientists have utilized artificial intelligence (AI), especially neural networks (ANNs), to predict reservoir properties. This talk reports a comparative study of two types of neural networks, a multiple-layer perception (MLP), with back propagation neural network, and a general regression neural network (GRNN). The viability of these techniques are demonstrated on well log data and seismic attributes from sandstone reservoir in south of Algeria. This study utilizes the basic logs including gamma-ray (GR), interval transit time (DT), shale volume (VSH), bulk density (RHOB), deep later log (LLD) and corrected porosity (NPHI) and five attributes (instantaneous frequency, instantaneous phase, RMS amplitude, half energy and arc length) to predict porosity, permeability and lithofacies in cored and uncored wells. The agreement between the core data and the predicted values by neural networks demonstrate a successful implementation and validation of the network's ability to map a complex non-linear relationship between well logs and permeability and porosity. Also the results show that the application of the general regression neural network (GRNN) gives a relatively better performance than the multiple-layer perception (MLP).

## 667976 Variations in formation-water salinity and its bearing on oil gravity (API) in a shallow heavy oil bearing sandstone reservoir in Ratqa Field, North Kuwait

*K.I. Sultan, A. Aziz, S. Al-Zanki and A. Al-Ashwak*

The extensively drilled Miocene Lower Fars Formation hosts heavy oil in the Ratqa Field of North Kuwait. The thickness of the formation ranges from 750 feet in the south to 900 feet in the north. The formation comprises alternations of fluvial to estuarine channel sands and associated overbank shales, ranging in depth from 260 feet in the south to 550 feet in the north. It is capped by a shale, which is considered the regional top seal. The sands are located along a relatively gently sloping SW-NE structural monocline, without any observable structural or stratigraphic entrapment geometries. Large variations in formation-water salinities have been observed from well testing and from log-derived estimates. The presence of very low-salinity water at shallow depths of 200–300 feet and great increase in the salinity with depth, in places, indicates possible contamination of formation water having over 100,000 ppm as NaCl concentration, with the relatively fresh water.

This presentation gives the results of an innovative study based upon an integrated analysis of formation-water salinity and oil gravity (API) distribution across the field. Log-derived salinity and porosity measurements from 84 wells were used to map formation water salinity and porosity variations across the field. They indicate the presence of permeability compartments in the reservoir, attributable to the possible presence of faults and/or lithofacies variations. Mapped oil API gravities ranging from 18 to 10 degrees, across the field, indicate a general deterioration, towards the south and southwest. Observed trends in API and salinity distributions are indicative of a causal relationship. Geological sections constructed from log-correlation profiles reveal that gravity-driven fresh water incursions, downdip, from the south and southwest to the north and northeast, are

responsible not only for a SW-NE regionally tilted oil/water contact, but also for water-washing and further degradation of the heavy oil, in the south and southwest. It is further postulated that updip migration of oil is arrested by the downdip counter movement of formation water, facilitating hydrodynamic entrapment of the oil. This is supported by large variations in the formation water temperatures in the fresh-water swept, high porosity and permeability corridors of the reservoir, indicating breaching of the shales in places. In the absence of seismic control, formation-water salinity variations yield useful insights into the hydrodynamic setting and reservoir character.

## 684482 Sedimentology, diagenesis and reservoir characteristics of Eocene carbonate, Sirt Basin, Libya

*G.H. Swei and M. Tucker*

Hydrocarbons in the Sirt Basin of Libya have been found in multiple clastic and carbonate reservoirs from Precambrian to Oligocene age. The Middle Eocene *Nummulite* accumulations of Gialo Formation form an important hydrocarbon reservoir interval within the Mesozoic – Cenozoic Sirt Basin. The basin originated by large-scale subsidence and block faulting commencing at the end of the early Cretaceous and continued to develop into the Miocene and perhaps to the present-day. Reducing risk in exploration demands an understanding of reservoir facies development, which is governed by the type and distribution of depositional facies and their diagenetic history. Six depositional facies have been identified using detailed core descriptions, petrographic textures and the faunal assemblages. These are: *Nummulite* facies, *Nummulitic Discocyclina* facies, *Nummulitic Operculina* facies, *Discocyclina-Nummulite* facies, bioclastic facies and *Mollusca* facies. These facies and microfacies can be interpreted as having accumulated in open marine, fore-bank and bank setting. Well-preserved large benthic foraminifera dominate the faunal assemblage in the Gialo Formation indicating deposition within the photic zone. Present-day reservoir characteristics of the Gialo Formation are the net result of modification to the original depositional characteristics caused by diagenesis. This diagenesis took place on the seafloor, under burial, and in the meteoric diagenetic environments. Petrographic and petrophysical studies indicate that porosity and permeability in the Gialo Formation reservoir are the result of the depositional environments and diagenesis.

## 670192 Early and charge-related diagenetic controls from rock types: Arab C and D reservoirs, South Rub' al-Khali Basin, Saudi Arabia

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The South Rub' al-Khali Company Ltd (SRAK) is an Incorporated Joint Venture between Shell Saudi Ventures Limited (50%) and Saudi Arabian Oil Company (50%) and was set up in order to explore for non-associated gas in the South Rub' al-Khali Basin as part of the Natural Gas Initiative in the Kingdom of Saudi Arabia. The Arab C and D reservoirs in the Kidan Field of the South Rub' al-Khali Basin have recently been the targets of a well drilled by the SRAK Venture. A total of 350 ft of continuous core was obtained to characterize reservoir properties and interpret key processes controlling their distribution across the field. Depositional environments and early diagenetic patterns provided the template for burial and charge-related modification of rock properties. Distinct reservoir rock types have been differentiated based on petrographic observations, core porosity, core permeability and MICP (mercury injection capillary pressure) data.

This presentation focuses on the results of the detailed diagenetic and geochemical study that allows the interpretation of the key processes controlling the differentiated rock types in Arab C dolostone units and Arab D ooid grainstone units. Dolostone reservoir properties in the Arab C are mainly controlled by the presence/absence of late calcite and/or late anhydrite plugging of intercrystalline porosity. The key diagenetic processes recorded in rock types from Arab D grainstones are: early cementation, compaction, burial cementation (including calcite, fluorite and anhydrite), late leaching and late charge-related cementation (calcite and saddle dolomite). The rock types are mostly stratigraphically defined units, in spite of the recorded complexity of diagenetic processes, associated diagenetic products and pore size distributions. The stratigraphic arrangement of the rock types in the studied core responds to depositional and early diagenetic controls. The late diagenetic products follow the early diagenetic template, nevertheless understanding the impact of late diagenesis has proven key to predict the rock properties across the field and construct new reservoir models.

## 725707 Advances in time-lapse reservoir monitoring using the new generation of radar satellites

*A. Tamburini, F. Novali, S. Cespa and G. Falorni*

Surface deformation monitoring provides unique data for observing and measuring the performance of producing hydrocarbon reservoirs, for enhanced oil recovery (EOR) and for carbon dioxide capture and storage (CCS). To this aim, radar interferometry (InSAR) and, in particular, multi-interferogram permanent scatterer (PS) techniques are innovative, valuable and cost-effective tools. Depending on reservoir characteristics and depth, oil or gas production can induce surface subsidence or, in the cases of EOR and CCS, ground heave, potentially triggering fault reactivation and in some cases threatening well integrity.

Mapping the surface effects of fault reactivation, due to either fluid extraction or injection, usually requires the availability of hundreds of measurement points per square kilometer with millimeter-level precision, which is time consuming and expensive to obtain using traditional monitoring techniques, but can be readily obtained with InSAR data. Moreover, more advanced InSAR techniques developed in the last decade are capable of providing millimeter precision, comparable to optical leveling, and a high spatial density of displacement measurements, over long periods of time without need of installing equipment or otherwise accessing the study area.

Until recently, a limitation to the application of InSAR was the relatively long revisiting time (24 or 35 days) of the previous generation of C-band satellites (ERS1-2, Envisat, Radarsat). However, a new generation of X-band radar satellites (TerraSAR-X and the COSMO-SkyMed constellation), which have been operational since 2008, are providing significant improvements. TerraSAR-X has a repeat cycle of 11 days while the two sensors of the COSMO-SkyMed constellation have an effective repeat cycle of just 8 days (the third sensor has already been successfully launched and is presently in the calibration phase). With the launch of the fourth satellite of the constellation, COSMO-SkyMed will have a revisiting time of just 4 days, allowing "near real-time" applications. Additional advantages of the new X-band satellites are: a higher sensitivity to target displacement and a higher spatial resolution. In this study we present examples of X-band applications to reservoir monitoring with the aim of highlighting the technical features of the new sensors, the importance of continuous data acquisition and standardized acquisition policies for all InSAR applications.

## 677253 Hydrocarbon charge and reservoir pressure history of the carbonate stringer play in South Oman: Implications for pre-drill pore pressure risking

*P.N. Taylor, A. Al Harrasi, C. van Eden and M. Al Ghammari*

The Ara Stringer Play in the South Oman Salt Basin contains sour oil and gas fields reservoired in carbonate slabs encased within salt. Hydrocarbons occur in a depth range of 2.5 km to 5.5 km with reservoir pressures ranging from hydrostatic (10–11 kPa/m) to near-lithostatic (22 kPa/m) gradients. Similarly, in-place hydrocarbon fluid densities vary widely, from 3 kPa/m to 8 kPa/m. Such variability in reservoir pressure and fluid density present a challenge for the design of safe and cost-effective drilling and completion strategies. Of particular concern is the combination of dry gas and hard overpressure, which could lead to well head pressures of up to 100 MPa (14,500 psi) at 5 km. To address this uncertainty we have completed an integration of reservoir pressure data, seismic data, fluid pressure-volume-temperature (PVT) data and geochemical data to allow the construction of a model for the pre-drill risking of likely pressure regime and hydrocarbon fluid types.

Previous work has shown that stringers which have pore pressures close to a hydrostatic gradient today should have been highly overpressured prior to a "deflation" event in the geologic past. Our observations on the hydrocarbon fluid characteristics support a scenario in which gas-condensate accumulations have originated from a palaeo oil phase within overpressured reservoirs. These oil accumulations were subsequently depressurised to allow separation and segregation of a gas phase. In the event that a "deflated" stringer is re-pressurised due to further burial, the saturation pressure of the mixture will be exceeded once again and the two-phase accumulation will revert to a single-phase oil column. Therefore highly overpressured gas reservoirs are only expected when the oil and gas phases are physically isolated prior to re-burial. Structural separation of the oil and gas legs of a palaeo-accumulation in the Ara Stringer Play has been observed.

The consequence of a phase separation/segregation model of gas occurrence is that the density of the segregated gas-condensate fluid is dependent upon the reservoir pressure (depth) at the time of deflation to hydrostatic conditions. There is, therefore, a strong depth dependency to the predicted fluid character, with in-place density increasing with depth. This knowledge can be used to optimise engineering decisions, rather than relying on the "worst-case scenario" of lowest density fluid properties and highest reservoir pressures observed within the play.

## 680297 Application of C7 hydrocarbons technique to geochemical evaluation of the Asmari and Bangestan reservoir oils in Marun oil field

*F. Tezheh and B. Alizadeh*

The purpose of this study was to examine the potential of C7 light hydrocarbons as biomarkers for petroleum exploration to geochemical evaluation of the Asmari and Bangestan reservoir oils in Marun oil field. The oils from the Asmari and Bangestan reservoirs have a variable $\delta^{13}C$‰ ratio -27.10 to -26.77‰ PDB, and Pristane/Phytane ratio from 0.78–0.91, implying the source rock is marine marl-carbonate. The isomeric parameters of C7 included single-branched and multiple-branched heptanes and isomeric pairs, such as nC7/Methylcyclohexane ratio *versus* Toluene/nC7 ratio, 2-MH+2, 3-DMP *versus* 3-MH+2, 4-DMP, n-Heptane ratio *versus* iso-Heptane ratio. The ratios for nC7/Methylcyclohexane and Toluene/nC7 ranged from 1.5–1.8 and 0.53–1.23, respectively. The n-Heptane and iso-Heptane values ranged from 30.5–39.3 and 1.55–1.95, respectively; and the iso-alkanes (3RP), cyclopentanes (5RP), cyclohexanes (6RP) ratios ranged from 20–47.5%, 10–15% and 41–70%, respectively. The use of this technique as a qualitative tool shows that all the oils from the Asmari and Bangestan reservoirs were super mature, free of biodegradation and generated from marine marl-carbonate source.

## 688025 Deterministic *versus* stochastic discrete fracture network (DFN) modeling: Application in a heterogeneous naturally fractured reservoir

*M. Travakkoli, S. Khajoee, R. Malakooti and M.S. Beidokhti*

Fracture modeling is a multi-step process involving several disciplines within reservoir characterization and simulation. The main idea is to build on geological concepts and gathered data such as: (1) interpretation of faults and fractures from image log data and 3-D seismic; (2) use of field outcrop studies as analogs for conceptual models; and (3) use of seismic attributes as fracture drivers. The purpose of modeling fractures is to create simulation properties with the power to predict the reservoir behavior. This note applies the concept of discrete fracture network (DFN) in a unique and comprehensive study of fracture modeling in one of the naturally fractured carbonate reservoirs of the Middle East.

A discrete fracture network is a group of planes representing fractures. Fractures of the same type that are generated at the same time are grouped into a fracture set. Each fracture network containing fractures has at least one fracture set but may have many. The simplest fracture sets are defined deterministically as a group of previously defined fractures, either as a result of fault plane extraction from a seismic cube, or as previously defined fractures. Fractures modeled stochastically can be described statistically either using numerical input, or properties in the 3-D grid. Properties in the 3-D grid can vary in 3-D and can easily be modeled using seismic attributes from 3-D seismic data. The scale-up fracture network converts the discrete fracture network (with its defined properties) into the properties that are essential for running a dual porosity, or dual permeability simulation. A simple simulation model is developed for three different grid types, using the software ECLIPSE 100, grid without DFN modeling, deterministic DFN modeling and stochastic DFN modeling. The results of the reservoir simulation indicate that cases with Stochastic DFN have a better result (history match) than cases with Deterministic DFN and the grid without DFN.

## 726221 Fluid status and saturation assessment in low-resistivity-pay carbonate reservoir using core scale petrophysical and resistivity modelling

*F. Umbhauer, J. Leduc, E. Guyotte and A. ElSadawi*

Fluid status definition for completion strategy, or reliable saturation evaluation for hydrocarbon-in-place and reserves estimation in heterogeneous carbonates reservoirs, based on wireline resistivity logs, is often uncertain as these reservoirs often deviate from Archie's Law. This can be explained by small-scale heterogeneities (patchy macroporous

oil zones embedded in a microporous matrix), which can generate an excess of conductivity (electrical bypass through water-saturated microporous connected path). Applying Archie's Law with the standard m and n = 2 values in such cases may lead to erroneous water-saturation computation, with serious consequences on fluid status, completion strategy and project economics.

A methodology has been developed to tackle this problem by: (1) modelling reservoir heterogeneity at core scale using commercial geomodelling software, providing a reference oil volume calibrated by core petrophysical data (CT scan 3-D imaging, minipermeameter, porosity, permeability, capillary pressure); and (2) checking the accuracy of the model through forward modelling using a research 2-D resistivity modelling software that simulates the invasion process, by comparison with the acquired wireline resistivity logs response.

This methodology was applied to a vuggy interval ("leopard-skin texture") of a carbonate reservoir of Paleocene age, in the Sirte Basin, onshore Libya. The water saturation derived from resistivity logs interpretation with standards Archie's parameters reached 77%, not consistent with drill stem tests (DST) production watercut values. Core-scale model provides an average saturation of 51%, which allows reproducing field watercuts. The forward 2-D resistivity modelling based on this model reproduced the acquired wireline laterolog curves and derived true resistivity profile, after adjustment of water salinity, consistent with regional data.

In the absence of any nuclear magnetic resonance (NMR) or SIGMA log acquisitions, low-resistivity pay intervals in this reservoir have been successfully characterized. This was possible because the complete coring and testing program permitted a good calibration of petrophysical and electrical properties, an accurate modelling of reservoir heterogeneities, and a successful core-log upscaling process. Providing equivalent zones could be diagnosed through well data (log imagery) and geological knowledge (correlations) along uncored well sections, resistivity-derived saturation can be corrected thus leading to effective decisions for completion strategy.



## 681818 Quartz cementation in a deep and hot sandstone reservoir: The Devonian Jauf reservoir in Ghawar Field, Saudi Arabia

*C.P. van Dijk*

The estuarine to shallow-marine sandstones of the Devonian Jauf Formation form a deep and hot gas reservoir where clay coatings on detrital grains are essential for the preservation of porosity. In the absence of clay coats, sandstones have lost almost all porosity due to massive cementation with pore-filling quartz. However, sandstones with extensively clay-coated grains also commonly appear to contain high percentages of quartz cement, which is thought to have nucleated on detrital quartz grains at breaks in the clay coats and then grown out into the adjacent pore space. The origin of quartz cement in the clay-coated sandstones and the controls on clay-coat distribution are the focus of ongoing research.

The development of quartz cement in the Jauf reservoir was studied by measuring clay-coat surface coverage of quartz grains in a suite of samples encompassing the range of quartz cement content and porosity values. It appears that sandstones with less than 90% surface coverage are pervasively cemented with quartz, causing almost complete porosity loss in those samples. In those samples, large parts of the quartz grain surface were unprotected, allowing quartz to nucleate on many detrital quartz grains. Porosity is only preserved in sandstones with clay coat surface coverage above 90%. These samples show a rough trend of decreasing quartz cementation with increasing clay-coat coverage, although quartz cement abundance displays considerable variation for any one clay coat coverage value. This suggests that breaks in clay coats played a profound role in quartz cementation, although other factors could also be important.

In practice, the frequency of breaks in clay coats may be evaluated by counting the number of quartz grains showing associated quartz cement in a thin section. This was tested on an abundantly quartz-cemented sandstone with measured clay coat coverage of 99.8%. This sample contains a high frequency of quartz grains with associated quartz cement, suggesting the frequent occurrence of breaks in clay coats. The frequent breaks would have facilitated the extensive quartz cement growth.

## 680522 Integrated static reservoir modeling of a Khuff reservoir, North Oman

*C. von Winterfeld, P. Bizarro, B. Laksana, I. Aghbari, M. Claps, Z. Kindi, H. van Alebeek, M. Moranville, S. Mahrooqi, T. Barodi and T. Aigner*

The Khuff Formation of the Arabian Peninsula comprises mixed carbonate/evaporitic sequences of Late Permian – Early Triassic age deposited on a widespread epeiric ramp attached to the Arabian Shield. The Upper Khuff oil and gas reservoir is characterized by lithological and reservoir quality heterogeneities as a result of both depositional history and diagenetic overprint. Further to its gas discovery and initial production, Petroleum Development Oman (PDO) has recently updated the Upper Khuff geomodel by integrating new data, such as reprocessed seismic volumes, appraisal well results, and core and fluid data.

Depositional/stratigraphic modeling was carried out based on facies analysis of cores, log interpretation and outcrop analogues. This allowed a detailed description of the vertical evolution and lateral variations of the carbonate ramp, from open-marine shelf, to oolitic/skeletal shoals and mud-evaporitic tidal flats. A high-resolution sequence-stratigraphic framework was built for the reservoir zones combining subsurface data and North Oman outcrop analogues, enabling subdivision of the entire Upper Khuff into third-order sequences and characterization of the flow units in terms of depositional cycles. The resulting layering scheme has proved to be correlatable at field scale. Reservoir rock types were defined to describe the reservoir matrix behaviour combining sedimentological, diagenetic and petrophysical data. These were obtained by combining lithologies and depositional facies into one single classification scheme, thus allowing identification of rock volumes with similar reservoir quality.

An appropriate Petrel grid was designed not only to capture the reservoir heterogeneity with sufficient detail, but also to prevent runtime excess. Petrophysical properties were populated in 3-D by conditioning to facies and rock types in order to capture the reservoir heterogeneities. By combining seismic fault pattern, curvature analysis and well interpretations, fracture models were generated and implemented in the dynamic simulation. The reservoir uncertainties were handled by defining their ranges and applying an experimental design process to evaluate their impact on stock tank oil initially in-place (STOIIP) and gas initially in-place (GIIP). Several static realizations were generated using combinations of these parameters. The final selection of subsurface scenarios was achieved by iteration with the dynamic reservoir simulation to capture the full range of reserves uncertainty.

## 680938 Critical factors of carbonate pore systems: Implications for reservoirs in the Middle East

*O. Weidlich, S. Lubeseder and K. Flender*

Generating predictive models for reservoir quality distribution is challenging for carbonate reservoirs. Usually, quantitative porosity data for these models are exclusively derived from conventional core-plug measurements or log data (log-derived effective porosity, bulk density, interval transit time, and nuclear magnetic resonance in rare cases). For this study, conventional porosity-permeability plots from plugs and log data of Cretaceous and Jurassic carbonates were analysed using data from several offshore wells in Qatar. The following observations are based on data from Kharaib, Yamama, Upper Sulaiy, Lower Sulaiy and Arab samples: (1) Porosity-permeabilty plots of the above stratigraphic units show a significant overlap of data despite some minor trends. (2) Core plug porosity data do not decrease with depth. (3) Cross plots of log-derived and core-plug porosities show no trend; for example core-plug porosities were higher, similar or lower than equivalent porosity log data (notably neutron pososity).

Our observations suggest that additional parameters need to be considered to improve reservoir models. The concept of reservoir rock types has been repeatedly regarded as an effective tool that integrates geologic observations with porosity and permeability data. We combine under consideration of sedimentologic and diagenetic factors conventional porosity data from plugs and logs with image analysis-based pore size, analysis from high-resolution core photos and thin sections. With this approach we established a six-fold reservoir rock type concept for the investigated Jurassic – Cretaceous carbonates to better characterize the variability of pore space and pore geometries of reservoir units.

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## 680793 Modeling smectite to illite transformation and the effect on compaction and overpressure development

*Y. Yang and J.E. Iliffe*

Smectite illite (I/S) transformation is part of the lithification process of fine-grained sediments. We constructed and calibrated a coupled kinetic I/S transformation and mechanical compaction model in which the Arrhenius Equation describes the rate of transformation and I/S grains collapse. The model accounts for porosity reduction and overpressure development contributed by the I/S transformation. The overpressure contribution results from the transfer of effective stress born by the I/S grains to pore water due to the collapse of I/S grains. The model is controlled by the initial expandable fraction in I/S and the temperature/time history. All together 320 mudstone samples were analyzed by high-quality X-ray diffraction (XRD) analysis for their mineral contents and expandable content in the mixed-layer illite/smectite.

Below 70°C, I/S transformation barely starts. Our dataset shows that expandable fraction in I/S for the samples with the temperature less than 70°C, that is the value at deposition, can vary from 40 to 100%, a reflection of different sources of I/S. The large variation of expandable fractions in I/S at initial deposition impose difficulties in modeling the I/S diagenesis. We chose a well with a thick homogeneous mudstone section in our model calibration to minimize the effect of the uncertainty of initial expandable fraction. The predicted results from the constructed model agree well with the measured data for the calibration well and also a blind test well. For our dataset, the large range of expandable fraction can be modeled using a different range of initial expandable fractions and reasonable temperature/time histories.

Since the blind test well has almost the highest initial expandable in I/S and high temperature in the history, we used it to investigate the maximum effect of I/S transformation on porosity and overpressure based on the assumption of no dissipation of overpressure contributed by I/S diagenesis. The maximum porosity reduction is 0.02 and the overpressure only 4 MPa. In reality, the over-pressure contributed by I/S transformation will dissipate and the effect on overpressure will be much less. Our study concludes: (1) the initial expandable content in I/S can vary in very large extent, in the range of 40–100%; (2) our constructed model describes the I/S transformation and its contribution to compaction and overpressure satisfactorily well; and (3) the effect to porosity and overpressure is very limited.

## 705377 Origin and occurrence of illite clay mineral in Unayzah Sandstone reservoirs in Central Saudi Arabia

*S.R. Zaidi, S. Shen, A.A. Al-Shehry and S. Mehta*

The Unayzah (Late Permian) sandstone reservoirs in Central Saudi Arabia are important sources of light sulfur-free crude oil and gas. However, the quality of the reservoirs can vary significantly based on the amounts of clay minerals (especially of illite) and quartz cement present in the reservoirs. It has also been observed that illite clay in amounts as little as 2–3 wt% can cause a precipitous decline in the permeability and productivity of a reservoir. In order to evaluate the nature and amount of illite clay in the Unayzah reservoirs, 69 core plugs from 25 wells spanning a depth (temperature) range of 6,200 to 15,500 feet were analyzed by X-ray diffraction (XRD) and environmental scanning electron microscope (ESEM). The results show that illite clay mineral occurs as domains, aggregates, pore linings or infillings, coatings around stable grains, and bridges between grains. Those illite clays can be classified into five types based on petrographic analysis: (1) matrix illite; (2) illuviated illite; (3) illite coating; (4) illite from illitization of kaolinite; and (5) fibrous illite. Types 1, 2 and 3 are detrital in origin whereas types 4 and 5 are diagenetic.

Among the five types of illite clays, the fibrous illite is more important than others as it is typically diagenetic in nature and grows into pore space during burial diagenesis. The XRD and ESEM results indicate that up to 11 wt% diagenetic illite is present in the cores. However, the data do not show any definite illite trend with depth. The data suggest a large increase in the amount of fibrous illite between 14,000 and 14,500 ft, but then the trend appears to reverse itself below 15,000 ft, where the amount of illite is reduced by 50%. The study revealed that diagenetic illite in Unayzah is mainly related to K-feldspar-kaolinite reaction. However, at shallower depths it appears that the illitization reaction has not gone to completion, which results in non-equilibrium assemblages of illite, kaolinite and K-feldspar. In the samples enriched with detrital illite coatings, although kaolinite is converted to illite, there is still significant amount of K-feldspar present in the rocks. This suggests that detrital clays may be blocking pore fluids from further reaction. It may be possible to predict illite precipitation using a kinetic model based on Arrhenius approach. This will lead to better correlations of illite cement with reduction in porosity and permeability and in identifying potentially good quality reservoirs in areas yet to be drilled.

## 680564 Porosity prediction from seismic: Application in a giant offshore oil field in Abu Dhabi, United Arab Emirates (UAE)

*J. Zhang, R. El-Awawdeh, Z.J. Shevchek, N. Khouri, K.S. Jan, C. Harris and J. Reilly*

A recent reprocessing of a large ocean-bottom-cable (OBC) seismic dataset of a giant offshore oil field in UAE resulted in several significant seismic imaging, signal/noise, and detection improvements of several fault and horizon geometries which included new fault system sets never recognized before. In addition, seismic-amplitude fidelity was improved significantly and it has been confirmed by well-ties and subsequent acoustic-impedance inversion. This presentation mainly focuses on the description of the acoustic-impedance inversion and porosity-prediction processes. We have developed a new workflow based on the new dataset and performed feasibility study. The process mainly consists of four major steps: (1) rock property analysis; (2) impedance inversion; (3) porosity prediction from multi-attribute analysis; and (4) validation based on well data.

Several hundreds of regular wireline and cross-dipole sonic logs were acquired and several tens of ultrasonic measurements from core samples were performed across the field. Data was conditioned and analyzed to understand the porosity *versus* impedance and other rock physics trends. A relative narrow porosity *versus* impedance trend was observed in the dataset, which laid the foundation for our subsequent analysis. Acoustic-impedance inversion was performed in subsequent steps: (1) well-to-seismic tie and wavelet estimation; (2) earth model building based on interpretation and well data; and (3) band-limited impedance inversion and total impedance derivation. The inversion results, seismic amplitude volume, and seismic stacks were loaded into attribute analysis software where multi-attribute analysis was performed and porosity *versus* impedance and other attributes relationship was established. The porosity volume was then generated across the entire field based on the established relationship.

The porosity volume and extracted maps of several reservoir intervals were validated with well data, where high consistency was observed and the results are being integrated into geological model.

## 680483 Maximising recovery from thin oil columns, Part 2: Using geophysics for improved reservoir quality prediction and better drilling performance

*F. Zhu and G. Warrlich*

Petroleum Development Oman (PDO) is currently developing a Cretaceous (Shu'aiba Formation) matrix carbonate reservoir with a transitional thin oil column of 10 to 15 m as a waterflood with over 1,000 m long horizontal producers and injectors. In-depth geophysical studies added significant value in a number of areas: improved understanding of the reservoir extent, pre-drill prediction of porosity and fractures from quantitative interpretation (QI) work and borehole seismics to accurately predict the distance from the horizontal producers to the top reservoir.

An improved velocity model utilizing regional wells from a 40 km radius greatly reduced the depth uncertainties to < 0.5% and predicted an extension of the field to the southeast, resulting in a stock tank oil initially in-place increase of 20%. Quantitative interpretation volumes provided rock property and reservoir quality prediction for well placement and sequencing. The porosity distribution predicted from acoustic impedance (AI) ahead of the main drilling campaign was confirmed by the drilling results and continues to guide the well lengths and sequencing successfully. Semblance and discontinuity extractions predicted sub-seismic faults and fractures along the planned wells and improved well placement and reduced drilling risks.

Borehole acoustic reflection survey, based on seismic data acquired post-drilling in the borehole with a sonic tool, proves useful in validating distance from borehole to reservoir top and recognizing sub-seismic faults. The results are used in subsequent side-track strategy, nearby well placement to reduce unswept attic oil and understanding production behavior. In conclusion, geophysics has demonstrated impacts on field extension, reservoir modeling and optimal oil production beyond routine formation structure and fault definitions.