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Selected geoscience and upstream abstracts from IPTC 2007, Dubai

The following selection of abstracts is reprinted from the Proceedings of the International Petroleum Technology Conference IPTC 2007, held in Dubai, United Arab Emirates, 4 to 6 December, 2007. The IPTC Conference and Exhibition was organized by the American Association of Petroleum Geologists (AAPG), the European Association of Geoscientists and Engineers (EAGE), the Society of Exploration Geophysicists (SEG), and the Society of Petroleum Engineers (SPE). The abstracts that are published here were selected on the basis of their direct relevance to the Middle East petroleum geosciences and related upstream disciplines, and grouped into themes.

In each group, the abstracts are listed alphabetically according to the family name of the first author. In the electronic proceedings (CD-ROM), some abstracts were accompanied by either short outlines, several figures or full-length papers. The following abstracts only reprint the short abstracts, where available, by permission from the IPTC organizers.

EXPLORATION CASE STUDIES

IPTC 11726 Fast maturation in a mature basin: An example from a stringer discovery

Z. Al-Rawahi (PDO), A. Faulkner (PDO), A. Matvienko (PDO), N. Mayahi (PDO) and D.M. Boersma (PDO)

Proterozoic-Cambrian carbonate reservoirs occur at depths between 3 and 6 km in the subsurface of southern Oman. These reservoirs are typically over-pressured, encased in and sealed effectively by thick Ara evaporites and contain sour oil. They have been a focus for exploration since the late 1950s. The discovery in 1976 of commercial oil in these "stringers" opened up the Ara play and Petroleum Development Oman (PDO) has since then been actively exploring for these deep oil reservoirs in the South Oman Salt Basin. Compared to the more conventional reservoirs in Oman, the Ara stringers are complex and pose challenges both in the subsurface and to surface facilities design, which typically results in a long lag time between discovery and well hook-up.

Following the discovery of the Budour NE field in 2005, we were challenged to dramatically reduce the time to develop these reservoirs. Thirty-five years on, with surface facilities in-place and with several producing fields nearby, it was possible to accelerate the appraisal of the discovery and achieve early oil production. This was achieved through the formation of an integrated exploration and development team that could capitalise on existing infrastructure and local expertise, and was able to deal effectively with appraisal uncertainties. The team worked on the definition, quantification, and planning of the field development. This resulted in additional volumes, an acceleration of appraisal drilling, and the early hook-up of the discovery for extended flow testing in 2007, i.e. 18 months after discovery. The latter is a record within PDO for a deep oil discovery. This hydrocarbon maturation exercise will deliver fast reserves, early initial production and an accelerated full-field development.

IPTC 11695 Data acquisition and interpretation challenges in deep gas exploration wells

Hans de Koningh (PDO), William Walton (PDO), John A. Millson (PDO), Dieter Skaloud (PDO), Mohamed Salim Harthy (PDO) and Mohamed Al-Harthy (PDO)

Exploring for gas and gas-condensate reservoirs in Oman has in recent years been focusing on deep reservoirs in the Haima Supergroup. Formation evaluation is becoming increasingly challenging with increasing depth. Abnormal pressure regimes and high temperatures go hand-in-hand with severe borehole breakouts. These factors result in a difficult logging environment making it hard to acquire a good quality data set for formation evaluation leading to efficient completion decisions.

Reservoir compaction and cementation increase with depth and typically the reservoirs that are targeted are characterised by low porosity and low permeability. The calculation of water saturation at low porosity is very sensitive to errors. One porosity unit error in this environment will result in a 30 to 40% error in the calculated water saturation. In addition, the porosity system in the Haima Supergroup changes with depth. Microporosity becomes the dominant porosity

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system at larger depths and this has significant consequences for formation evaluation. In particular with reductions in the resistivity index, the electrical behaviour changes and residual gas saturation increases.

Production testing in Petroleum Development Oman (PDO) exploration setting invariably involves running a liner, completion and some form of fracture stimulation. Therefore, production testing is expensive and time consuming, putting more emphasis on an appropriate "test or abandon" decision. A good understanding of the range of uncertainty on all available data types and their associated interpretation are essential ingredients for the completion decision. A number of examples from recent exploration wells are shown where production test results are compared with pre-test well interpretations with the aim of capturing the lessons-learned and highlighting the progress made in recent years in PDO as well as demonstrating the remaining uncertainties.

IPTC 11705 Exploring for subtle stratigraphic carbonate traps within the upper Shu'aiba of Oman

Kees De Leeuw (PDO) and
Christophe Gonguet (PDO)

Since mid-2003, Petroleum Development Oman (PDO) has been successfully exploring the stratigraphic Upper Shu'aiba play in northern Oman. Play understanding has significantly evolved and to-date three discoveries have been made. Prograding Aptian shoals and mounds into the Bab Basin interfinger with argillaceous limestones and are truncated by Nahr Umr shales. Individual reservoirs, in the clinoform apex, are too thin to be resolved on seismic. Stacked clinoform geometries can be observed directly in seismic sections. Delineating these geometries, attribute maps and particularly spectral decomposition maps are used, enabling visualisation of tuning bands of the inclined sequences terminating against the Nahr Umr Formation. Frequency-slice analyses determine the potential location of reservoir belts or prospects. Spectral decomposition is used to predict reservoir thickness using calibrated analogues.

Sequence-based geological modelling has resulted in facies distributions over the Bab Basin and the carbonate platforms beyond. The detailed 3-D model constrains the general trends of the tuning belts observed in seismic. As seismic artifacts interfere with the actual primary reflections, false trends that do not align with the geological model may be discarded. Seismic modelling shows that porous reservoirs have similar impedance as the Nahr Umr Formation. The clinoforms imply that the top Shu'aiba is not a uniform hard-kick pick and the phase depends on reservoir thickness so that manual picking is necessary. Well placement and geosteering are key factors in increasing success and maximising the value of discoveries. Facies demands a vertical pilot hole placed downdip of an expected sequence and a horizontal sidetrack is designed to follow an individual clinoform stratigraphically updip where the reservoir is only a few metres thick. PeriScope™ (Schlumberger) has added value, and maximises the extent of producible reservoir without unwanted exits and converting a discovery into a producer within a period of one month.

IPTC 11689 Angudan revisited: Using old data to explore for new targets in a frontier area

James Graham McIlroy (PDO)

Newly acquired modern long-offset 2-D seismic data, in conjunction with gravity and magnetic data, has provided a more complete picture of the deep prospectivity of the South Oman Salt Basin. Deeper potential that was poorly imaged previously is now targeted to unlock future potential for the area. The Angudan area of the South Oman Salt Basin was first explored in the 1960s using surface geology and low-fold seismic data. This resulted in several shallow wells that tested seismic-delineated structural closures. The failure of these wells led to a shift of exploration to the more prospective and more successful areas in northern and central Oman during the following years. The discoveries in the 1980s refocused exploration to the south where the Ara carbonate stringers proved to be a valid and prolific reservoir. Although the Angudan area was revisited with improved seismic coverage, the data was not of sufficient quality to resolve the deeper horizons. The Angudan-1 well drilled in 1990 penetrated the deepest mappable marker but failed to find any reservoirs. It stopped short of the Ara carbonates. As focus has shifted again to the south in the last few years, the deeper South Oman Salt Basin reservoirs were targeted using long-offset seismic data and a 2-D grid down to one kilometre spacing. Although the rugged terrain and various access issues in the area caused access restrictions, an improved image of the Ara carbonates has been obtained. A combination of geophysical techniques has reduced the exploration uncertainties in this frontier area and improved our prospect risk assessment.

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IPTC 11684 Exploring for fractures in tight gas reservoirs, North Oman

John A. Millson (PDO), Joerg Mattner (GeoTech), van der Pal (PDO), D. Skaloud (PDO), W. Walton (PDO), Schrijver (PDO), H. Al-Shuaily (PDO) and M. Al-Harthy (PDO)

As gas operator on behalf of the Oman Government, Petroleum Development Oman (PDO) has been active in a mature basin for c. 18 years. The traditional focus for gas exploration in the north has been on deep Haima reservoirs. These have been successfully targeted in a proven Haima silicilastic "play fairway" where all the classic play elements have been recognised and areally defined in a target window of c. 4 to 5 km. The approach has led to the discovery and development of a number of significant deep gas/condensate fields including Barik, Saih Rawl, Saih Nihayda and Kauther. Periodic attempts (c. 5 year cycle) to move out of the fairway area based on a challenge of prior geological models, developed with new insights, have often led to disappointing results. Outside the mature fairway all the play elements (reservoir, charge, structure, seal) are still present but an additional overriding "reservoir recovery" play risk becomes significant. Reservoir recovery captures (at a play level) subtleties in reservoir composition/facies, burial history and charge timing that have a significant overprint on the overall play risk.

To manage the "operational" factors impacting reservoir recovery in the exploration arena ongoing work pursues optimising drilling, completion and testing procedures. The presence of an open fracture network in a recent discovery has triggered a possible geological "game changer" with the potential to significantly reduce recovery effectiveness risk and unlock significant additional gas volumes across a large area. With the aid of a number of key indicators (rock mechanical properties, recent flexure, fault orientation and late charge) a working model for the deliberate pursuit of fracture systems in an exploration setting (a "fracture play") is being developed. This workflow in conjunction with optimised operations may allow a redefinition of recovery effectiveness risk.

IPTC 11704 New exploration play in basal Burgan 'Unnamed Clastics', Kuwait

Sanjeev S. Thakur (KOC), Michael George Kumpas (KOC) and Areej Al-Darmi (KOC)

Unnamed clastics at the base of Burgan Formation offer a hitherto un-explored hydrocarbon play in onshore Kuwait. It is a sub-unconformity play and comprises a composite sequence with three systems tracts upwards, namely; transgressive, highstand and followed by another transgressive package. Thickness of the whole package varies between 10 and 145 ft (generally between 37 to 60 ft, net pay 40 ft). Sand bodies in the transgressive systems tract are discontinuous both laterally and vertically, and those of the highstand system tracts are fairly continuous sheets that shale-out in the distal settings. Thin channel sand bodies of the lower transgressive and highstand units entrap oil whenever the upper transgressive unit provides effective top seal. The effectiveness of the top seal depends on the vertical limits of incision by overlying lowstand Burgan clastics. The trapping is controlled by both stratigraphic and structural components. In most of the wells that target Lower Cretaceous or deeper units, casings are generally set within this unit, and often proper logs are not run across the section. However, some of the wells have a partial suite of logs and well cutting. The resource remained largely unaccounted and unexplored. The play has been identified in the Ratqa, Mutriba, Medina and Raudhatain areas. A case study is presented from the Raudhatain Area.

GEOLOGICAL STUDIES

IPTC 11764 Palynofacies and biomarkers of the Campanian Khasib Formation oil used to assess oil-source correlation and suggestion for other traps along the migration path, East Baghdad field, Iraq

Thamer Al-Ameri (University of Baghdad, Iraq) and Mohamed Zine (IHS Energy)

Palynomorph constituents and their maturation, Rock Eval pyrolysis, total organic carbon (TOC) analyses were carried-out on Upper Jurassic and Cretaceous formations in Iraq. These analyses were used to correlate the oil in the Khasib reservoirs and kerogen from the source rocks. The study also focused on locating possible oil traps along the predicted migration path in East Baghdad oil field. The gas chromatography of these oils showed wide ranges of biomarkers suggesting mainly liquid oil constituents of paraffinic hydrocarbons in the reservoir. Low non-aromatic C15+ peaks indicated their degradation and water washing. Oil biomarkers and CPI of 1.5 might indicate anoxic marine environment with carbonate deposition of an Early Cretaceous source rock. The recorded palynomorph constituents in this oil and associated water could indicate affinity to the Lower Cretaceous Chiagara and Ratawi formations. These formations are inter-

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preted to have generated hydrocarbons based on their TOC, high hydrogen potential, mature kerogen type II and palynofacies. In contrast the palynomorphs of the rocks of Khasib Formation did not generated hydrocarbons; however this latter formation could be considered as an oil reservoir. Accordingly, the palynomorphs have been included in this oil during its generation from the kerogen source of the Chiagara and Ratawi formations. Hence they migrated within the liquid hydrocarbons to the Khasib Formation through fractured and fault passageway imaged on the seismic section in Baghdad field. The increase in Pristane/Phytane ratios to greater than one, increased migration index to up to 0.9 and microfractured source rocks could confirm the interpreted migration model.

IPTC 11729 Integrated chemostratigraphic studies of the Khuff and Palaeozoic section in Kuwait

Ghaida Al-Sahlan (KOC), Abdul Aziz Al-Sajer (KOC), Husain Riyasat (KOC), Nadia Al-Zabout (KOC), Peter Wellsbury (Fugro-Robertson) and Jim Fenton (Fugro-Robertson)

Integration of new inorganic geochemical data with biostratigraphy has resulted in a robust, detailed chemostratigraphic correlation scheme for the Khuff and pre-Khuff Palaeozoic section in Kuwait. In much of the section, biostratigraphic data are limited, with prevalent non-marine or marginal marine facies precluding the consistent recovery required for biostratigraphic zonation. Where biostratigraphic recovery is poor, chemostratigraphic interpretation can be advantageous as it is not dependent on the presence or preservation condition of microfossils or palynomorphs. In this study the compositions of 47 major, trace and rare-Earth elements were determined by a combination of Inductively-Coupled Plasma – Optical Emission Spectrometry and Mass Spectrometry (ICP-OES and ICP-MS) in ditch cuttings samples from both the carbonate Permian-Triassic Khuff and clastic pre-Khuff Palaeozoic section. Inorganic geochemical data were subjected to multivariate statistical treatment to identify the chemical 'fingerprints' of individual subunits, and consequently to establish zonation and correlation schemes in the studied wells.

In addition to stratigraphic zonation and correlation, this chemostratigraphic analysis has provided information on facies mineralogy, and the depositional environment. Changing facies mineralogy can be distinguished by clear changes in lithology with depth documented by, for example, Ca/Al, Si/Al ratios and total immobiles (Ti + Hf + Nb + Y + Zr), in both the carbonate/dolomite Khuff Formation and the clastic Palaeozoic section. High levels of V/Cr, U/Th, U and Mo indicate organic-matter preservation in sediments often deposited in a reducing environment through both carbonate and clastic facies. Changes in provenance of the formations can be seen in changing rare-Earth element ratios in clastic sequences (e.g. LREE/HREE and Ce/Y). This study has demonstrated the applicability of the chemostratigraphic technique to both carbonate and clastic sequences, of ages varying from Proterozoic to Triassic.

IPTC 11743 The Late Permian-Early Triassic Khuff Formation in the Middle East: Sequence biostratigraphy and palaeoenvironments by means of calcareous algae and foraminifers

Jeremie Gaillot (Total)

The carbonates and evaporites of the Late Permian-Early Triassic Khuff Formation form widespread reservoirs across the Arabian Plate and concentrate the largest gas resources in the world. The material studied includes 1,500 samples from outcrops in Iran (Zagros), Turkey, Saudi Arabia and South China. The objectives of the study were: (1) to build a robust biotratigraphic framework based on a detailed description of algal-foraminiferal biotic content, (2) to characterize the depositional environments and their temporal successions during the Late Permian and Early Triassic. By comparing fossil distributions, the Middle/Late Permian Khuff deposits are divided into eight units limited at their tops by turnovers levels, corresponding to significant reshapings of biotic assemblages. During the Late Permian, the Zagros (Iran), Taurus (Turkey), South China, and even Japan, shared similar foraminiferal assemblages, which represented intermittently connected palaeobiogeographic provinces.

Palaeoecological results show that the structurally controlled palaeohighs were successively drowned and that the system evolved progressively from a rimmed platform towards an almost uniformly flat ramp. The major oolitic units (reservoirs) developed within high-subsiding areas by sediment volume funneling, mainly during the late Wuchiapingian (upper K4 reservoir equivalent) and Early Triassic (K2 reservoir equivalent). The thermal subsidence during the Neo-Tethys Ocean spreading is likely the main factor that drove the Khuff deposition on the Arabian Platform and can be related to the demise of the regional Permian fauna. The new framework is expected to provide an important tool for further subsurface studies and correlations.

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IPTC 11590 Integrated subsurface geology and biosteering: A case study from the Sajaa field, Sharjah, United Arab Emirates

Paul Robert Marshall (Fugro-Robertson), Trevor Burchette (BP) and K.S. Ali (BP)

A case study is presented to show how close integration of continual subsurface geological insight and well-site biosteering data generation and interpretation played a key role in ensuring commercial and technical success of the underbalanced, coiled tubing drilling (UBCTD) campaign at the mature Sajaa gas/condensate field. Reservoir pressure depletion had led to UBCTD being required to increase both rates and reserves. Commercial and technical success was known to depend heavily on maximisation of reservoir exposure in the multiple target intervals within Thamama Group limestones.

The field presented complex geology: major and minor folding and faulting; lateral facies variations, as well as problems in field boundary delineation. Despite exhaustive efforts, seismic interpretation was unable to provide sufficiently precise resolution for well planning and monitoring if the aim of maximised reservoir penetration was to be achieved. As the campaign progressed, the key role played in achieving the aim by the integration of subsurface geology, real-time gamma-ray and well-site biosteering (analysis of fossils and limestones from extremely small cuttings samples) was increasingly recognised.

Continued development of office- and well site-based techniques during drilling of 164 laterals in 28 wells led to optimisation of reservoir penetration in ways and to extents considerably beyond those initially anticipated. Optimisation was achieved as: (1) high percentage of borehole length in target; (2) extension of achievable reach (beyond initially believed limits); (3) curtailment of drilling for unachievable targets; (4) realignment of boreholes encountering unpredicted geological complications (including poor target parameters); and (5) by rapid re-planning of later trajectories based on interpretations obtained during drilling. The accumulated information was used during and after the campaign to: modify plans, generate new plans, improve geological understanding, reassess the completeness of the campaign, and form the basis of the proposal for a further campaign. Successful application of this technique with great future potential has continued elsewhere in the region.

IPTC 11460 Hydrothermal dolomitisation fronts: Implications on reservoir characterisation and modelling (Jurassic, Lebanon)

Fadi H. Nader (IFP), Rudy Swennen (Katholieke Universiteit Leuven), Benoit Vincent (IFP), Teddy Parra (IFP), Vanessa Teles (IFP) and Brigitte Doligez (IFP)

Hydrothermal dolomite (HTD) reservoirs are well known from exploration and development of hydrocarbon plays in the Middle East. Petroleum geoscientists query for means to model the related reservoir properties. This contribution describes the field geometry, petrography and geochemistry of hydrothermal dolomitisation fronts (Late Jurassic, Lebanon) and aims to investigate the relationship between diagenetic evolution and reservoir quality. The main application is to provide a methodology for HTD reservoirs modelling based on the internal facies distributions of dolomite bodies, and diagenetic evolution (fluid-rock interactions).

Dolomitising fluids circulate along faults and invade the nearby facies, preferentially according to the original porosity/permeability properties of limestone host-rocks. Enhanced porosity due to the initial hydrothermal dolomitisation of micritic limestones is observed at the margins of the front. There, sucrosic planar-e dolomites possess relatively high porosity and permeability (approximately 8% and 10 mD). The centre of the dolostone bodies exhibits over-dolomitisation, which results in an increased crystal stoichiometry (50–52 mole% $CaCO^3$) and broad, light $\delta^{18}O$ values (approximately 9.0 to 4.0 PDB). Such a recrystallisation process may have changed the porous sucrosic dolomite textures into (over-dolomitised) planar-s, interlocking crystalline textures with lower matrix porosity (< 6%) and permeability (< 0.5 mD).

Additional diagenetic phases postdate the hydrothermal dolomitisation, altering (positively or negatively) the dolostones with respect to reservoir quality. By identifying the complex diagenetic processes and associated fluid-rock interactions, a new approach is proposed for predicting and modelling HTD diagenetic evolution and reservoir quality. The significance of this contribution includes: (1) identifying distinct dolomite facies in HTD reservoirs; (2) stressing the role of diagenetic evolution in enhancing or destroying reservoir quality; and (3) providing a new approach for modelling HTD reservoirs through fluid-rock interaction, coupled with sedimentary evolution history.

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IPTC 11750 Chronostratigraphy and source rock presence within the Silurian Qusaiba of Qatar

Chris Reaves (ExxonMobil), Ismail A. Abdulla (QP), Robert H.S. Alway (ExxonMobil), Mamdouh Zahran (QP), Leonard Moore (ExxonMobil) and Stewart Molyneux (British Geological Survey)

The Qusaiba Formation is the primary source rock for the prolific Paleozoic plays being explored and developed in the Middle East. The supergiant Qatar North field accumulation alone is estimated to contain 900 TCF of recoverable reserves. We have evaluated stratigraphic and facies relationships within the Silurian, including the Qusaiba Formation, as part a systematic evaluation of hydrocarbon prospectivity commissioned by Qatar Petroleum QP). Well penetrations of the Silurian section in Qatar were integrated with the established regional distribution of the Silurian across the Arabian Platform. Biostratigraphic dating yielded a chronostratigraphic range of Early Silurian (Rhuddanian) to Late Silurian (Wenlockian), with an overall age range of 443 to 425 million years before present. These age dates improved the lateral correlation of second-order maximum flooding surfaces and led to revisions of the standard Silurian lithostratigraphic correlation.

The Qusaiba in Qatar was determined to contain three separate source horizons: (1) a Rhuddanian 'hot' shale restricted to paleo-topographic lows established on the underlying Ordovician; (2) A Mid-Aeronian 'hot' shale associated with the early Silurian maximum flood. This horizon is laterally extensive, but the thickest along the western margin of the Qatar Arch; and (3) A Wenlockian lean, 'cool' shale extending over the whole of Qatar. Organic geochemical and petrographic analyses were used to determine source type and richness. Samples were 'back-tracked' to determine original (thermally immature) organic carbon (TOC) and hydrocarbon potential (HI) values. 'Paleo-thermometry' data from palynomorphs (TAI), conodonts (CCI) and acritarchs (AAI) provided additional control on organic maturity.

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SEISMIC CASE STUDIES AND TECHNOLOGY

IPTC 11523 Accurate imaging of surface seismic data without a velocity model

Sverre Brandsberg-Dahl (BP), Brian Hornby (BP) and Xiang Xiao (University of Utah, USA)

We present a method for imaging surface seismic data that does not depend on a background velocity model. Instead of computing Green's functions in a background model, we use direct measurements from VSP data as Green's functions for the migration. These Green's functions will have all propagation effects intrinsically in the measurement: including all arrivals and all kinematic and dynamic effects caused by anisotropy and absorption. The VSP Green's functions can be used in a standard migration scheme for surface seismic that enables us to create a robust image of the sub-surface. Although the method is strictly only valid for v(z) media, we show that mild lateral variations can be handled. When the subsurface is laterally invariant or smoothly varying, the measured Green's functions can be used to image the surface seismic data accurately in locations away from the well-bore, however, lateral velocity variations will introduce some distortion in the image. Regardless of the velocity distribution, the VSP can always be used to image the surface seismic in the location of the VSP.

IPTC 11813 Incorporating seismic characterization results into Bul Hanine Geological Model

Nicolas Desgoutte (Beicip-Franlab), Abdulmalik Al-Abdulmalik (QP), Matthieu Pellerin (Beicip-Franlab), Gaël Lecante (Beicip-Franlab), Scott Robinson (Beicip-Franlab) and John McCallum (Total)

Bul Hanine field is located offshore Qatar with primary oil production from the Reservoir-X carbonates. In 2005 and 2006, Qatar Petroleum (QP) recognized that future development of this mature field would require a modern, state-of-the-art, reservoir model, and initiated several projects to achieve that goal: reprocessing and elastic inversion of the 1995 vintage 3-D seismic, petrophysical data collection and analysis, and comprehensive reservoir characterization. This paper illustrates how QP, with contractual assistance from PGS, Total and Beicip-Franlab, has applied advanced reservoir characterization techniques to constrain petrophysical property distribution using elastic inversion prod-

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ucts and therein reducing uncertainty in a reservoir model.

Following detailed rock-typing core and log analysis from approximately 5,400 ft of core and from 26 wells, and logs from 90 well penetrations, the team observed that there was considerable heterogeneity in this "hard" well data, and that distribution of the petrophysical properties between wells would suffer in the absence of additional control. To address the lack of inter-well control, an attempt was made to extract reservoir property information from the seismic data. Using optimally reprocessed existing 3-D seismic data (to eliminate noise and preserve relative amplitudes) and pre-stack elastic inversion, advanced reservoir characterization techniques yielded volume data including lithology, lithology probability, and porosity that could be used as geostatistical constraints.

Initially, a detailed petro-elastic analysis was performed on select wells to calibrate well-derived elastic properties with seismic data in order to design the most appropriated seismic characterization workflow. The results demonstrated that acoustic and elastic impedances could be used to discriminate calcites, dolomites, and anhydrites. Well analysis also indicated a robust relationship between impedance and porosity and each dominant lithology. Subsequently, a pre-stack inversion was conducted prior to 3-D discriminate analysis to produce dominant lithology and associated probability volumes. Following this, seismic reservoir characterization resulted in generation of a lithology-based porosity volume.

During the geostatistical modeling, dominant-lithology probability volumes were used as a cosimulation parameter for generating a lithology model, and the seismic porosity volume was used as a cosimulation parameter for porosity distribution, resulting in a high-resolution static model of Reservoir-X. This work demonstrates the added value of pre-stack seismic reservoir characterization for modeling of the Reservoir-X carbonate reservoir. In addition to porosity, this technique gives light to lithology changes throughout the reservoir, providing otherwise unobtainable information of rock-type distribution.

IPTC 11757 The BP 4-D story: Experience over the last 10 years and current trends

Dave G. Foster (BP)

For more than a decade, BP has been deploying a growing range of 4-D seismic technologies, and applying these to a variety of reservoir situations. This paper reviews the "macro" view of BP's 4-D experience and offers insights into possible emerging future trends, giving a wider context to complement other IPTC papers on specific 4-D technologies.

BP has experience in about 80 operated and 30 non-operated surveys around the world (counted as per field, expected to end 2007), concentrated in the North Sea and Gulf of Mexico (GOM). Reservoir types surveyed include clastic, carbonate and fractured under different recovery schemes, including depletion, secondary water-floods and tertiary EOR schemes. The main historical "mode" of 4-D data acquisition for BP has been with marine surface-tow streamer operations, acquired every 2 to 5 years. However, by the time of this presentation, BP will have installed and be operating its third permanent ocean bottom cable (OBC) seismic monitoring system.

The bulk of successful track-record to date has been in oil reservoirs under water-flood, using streamer data. Significant value has been generated through improved targeting of infill and development wells, and increasingly through improved reservoir management and reducing drilling hazards. Permanent seabed cable systems are now providing high-quality, wide-azimuth 3-D seismic images and 'on demand' reservoir surveillance to meet the development challenges of the most complex reservoirs. Other emerging technologies include land 4-D, permanent in-well 4-D VSPs, passive seismic monitoring, and development of quantitative integration of 4-D data into reservoir models. With 4-D now being increasingly accepted as a valuable and maturing reservoir management tool, and with many fields and projects around the world moving into the production phase, a global expansion in 4-D activity, certainly within BP, is now emerging. This will require careful deployment of the most appropriate technologies from an ever-expanding 4-D toolkit, as considered in this paper.

IPTC 11789 Reservoir monitoring using permanent in-well seismic

Brian Hornby (BP), Olav Inge Barkved (BP), Brock Williams (BP) and Tad Bostick, III (Weatherford)

The world's first successful installation of a permanent borehole seismic system in an offshore production well was executed at Valhall. The system is fibre-optic based and consists of 5 levels of 3C seismic sensors spaced 13.5 m apart. Permanent borehole seismic is seen as complementary to the permanent seabed seismic array with the following goals: (1) 4-D seismic calibration using the directly recorded downhole signal to calibrate the surface seismic signal. This might best be done in conjunction with instrumented seabed seismic receivers

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for full-field monitoring. (2) 4-D VSP with several wells instrumented, which uses surface sources and downhole sensors for reservoir monitoring. (3) Micro-seismic passive monitoring of faulting caused by reservoir compaction and fluid fronts and active monitoring of cuttings injection and well stimulation. Surveys have been conducted with simultaneous acquisition of permanent seabed and borehole arrays using both active surface sources and passive noise. The active seismic data are of good quality and processing yields high-resolution images to a distance of 400 m from the borehole, complementing the lower-resolution surface seismic data. Time-lapse measurements were conducted with the main objective being to measure pressure changes in the reservoir due to injection from a nearby well. In parallel passive data are analyzed for potential for reservoir monitoring of fluid fronts using micro-seismic data. Additional work relates to calibration of the 4-D seismic response for changes in the overburden.

IPTC 11777 Vertical seismic profile (VSP): Beyond time-to-depth

Brian Hornby (BP) and Jianhua Yu (BP)

VSP or Vertical Seismic Profile was originally designed and is currently primarily used, to give us time-to-depth for seismic-well tie. Beyond time-to-depth a number of possibilities exist. Recently, there has been considerable interest in VSP imaging with extensive surveys being acquired both on land and offshore. Modeling studies using full-waveform finite-difference method (FDM) show us what we can image for a particular acquisition geometry and geology, with best image results seen with 3-D VSP surveys incorporating a large VSP array in the well and an areal grid of surface sources obtained using a seismic shooting vessel. Traditionally, VSP imaging has been implemented using surface seismic processing algorithms. However, the VSP geometry poses its own challenges and unique opportunities. In this talk we will discuss the state-of-the-art of the technology, what technologies are appropriate for different settings, and what the future may bring. Results will be shown from deepwater Gulf of Mexico prospects and we will discuss how these results have impacted our understanding of the reservoir and reduced risk on development well placement. On imaging algorithms we will examine some exciting new developments to develop specialized algorithms to take advantage of the opportunities posed by the VSP geometry. These developments include controlled local beam methods to improve image quality, imaging using multiples and interferometric imaging of salt flanks and structure below complicated overburden.

IPTC 11812 Characterisation, origin and repartition of tar mat in the Bul Hanine field in Qatar

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Both core description and the log detection have evidenced the presence of bitumen inside the Bul Hanine field, which can be particularly abundant in some wells. This tar mat severely impacts reservoir production behaviour because it acts as a permeability reducer and a barrier to flow. Properly understanding its distribution and its propagation throughout the reservoir is therefore essential for the prediction of reservoir performance under various development plans, for instance when water flooding the field. The objectives of this study were to: (1) characterize the tar mat and understand its formation mechanism; (2) evaluate its occurrence in wells in terms of type, thickness and distribution, in the various rock types; and (3) propagate this distribution in a 3-D reservoir model for the field. Fulfilling these objectives has provided more accurate volumetric estimations, taking the tar mat into account in the dynamic reservoir modeling, as well as in planning further development of the field.

Tar mat occurrence was investigated across more than 5,400 ft of cores from 26 wells, 90 well logs and a large number of cuttings samples. Two tar mats were identified in the reservoir. The upper tar mat was formed in the crestal area at an early stage of the oil-charging (early phase segregation?). The second major one was formed at deeper depth. The tar mat in the Jurassic reservoirs is composed of asphaltenes. Tar mat formation is explained as follows. (1) A charging of oil, expelled from the source rock, followed by (2) gravity segregation of Asphaltene Precursor Entities (APE) within the oil column on top of permeability barriers and paleo-oil-water contact. (3) The precipitation of asphaltenes triggered by a secondary light oil charge.

The methods applied in this study included geochemical characterisation of the bitumen of the Bul Hanine field, a quantification of the tar content in cores using simple techniques (optical observation, Rock-Eval, Iatroscan, image analysis), and extending this quantification through wire-line data in non-cored wells and then, subsequently across the field. In the reservoir model, through the relationship between reservoir quality (rock-type) and bitumen content, the distribution of tar mats can be inferred and traced across the entire field.

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IPTC 11360 Shake and Go: Advances in vibroseis technology

Christine E. Krohn (ExxonMobil), Ramesh Neelamani (ExxonMobil) and Marvin L. Johnson (ExxonMobil)

A new patented vibroseis acquisition method, "Shake and Go"SM, allows operation of multiple vibrators at multiple source points simultaneously and continuously with no waiting for between-sweep listening times or for between-vibrator slip times. This method allows for unsurpassed production rates. Model simulations, field gathers, and processed stacks are used to demonstrate excellent data quality compared to other high productivity methods. The cost of vibroseis land acquisition is directly related to the time it takes to shake each vibrator point and move to the next point. Shake and Go can be used to record seismic data at lower cost, or it can be used to record more data at the same cost with improved sampling of signal and noise. It is especially efficient for new point source and point receiver (MEM) acquisition without arrays.

Shake and Go, also called C-HFVSSM or "Continuous High Fidelity Vibrator SeismicSM", uses long segmented sweeps and HFVS separation. Measurements of the individual vibrator motion are recorded and used to derive a filter that optimally recovers individual seismograms from vibrators operating simultaneously. Cross-contamination from strong events, which are simultaneously recorded, are not observable in the individual recovered seismograms. Interference and harmonic noise from the continuous sweeping are limited to the end of a long record and can be removed with a new novel processing method. Because of the high production rates and high data quality, the new method is expected to dominate land acquisition in the future. We present analysis of the noise and show data comparisons for different vibroseis methods. We also overcome the limitation that there must be as many sweeps as vibrators or time delays to optimally separate records for simultaneous sourcing.

IPTC 11289 Plan view seismic interpretation: Applications in Kuwait

Michael G. Kumpas (KOC), Narhari Srinivasa Rao (KOC) and Areej Al-Darmi (KOC)

Deviation from exploration for conventional Albian-aged, clastic plays towards carbonate plays of a stratigraphic nature has prompted the use of plan view – horizontal seismic displays in the interpretation process as an additional means of data visualization enhancement. Significant improvements in accuracy and speed have been attained with the use of horizontal displays in the mapping of minor lineaments and faults with no visible, or minor throw on vertical seismic sections. Mapping practices include work on horizontal slices and slabs, which can be either horizon- or time-consistent. This approach to seismic interpretation has allowed the inclusion of seismic attributes, spectral decomposition, edge detection, coherence, dip, azimuth analysis, and other display enhancements into the interpretation process.

Lower Cretaceous carbonate plays are of emerging interest as exploration targets. These plays rely on fracture porosity, which is developed in close association with faults. Generally poor seismic data quality prohibits accurate fault identification on vertical sections. Here it has often been necessary to employ circumspect methods including the use of horizon volumes. These may even be based on vertically offset, but well-defined marker horizons that approximate the curvature of the studied event. Methods of this nature have been employed in the identification of stratigraphic features such as the edge of a Lower Cretaceous oolite play proximal to the Minagish field in southern Kuwait. Horizontal displays of seismic attributes were also used in mapping the extent of a flat spot in the Upper Cretaceous, and of a very shallow, Lower Miocene channel system in northern Kuwait. In the two latter cases it was extremely difficult to maintain lateral pick consistency among consecutive vertical sections.

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We conclude that for these types of plays, the level of accuracy attained in the interpretation of faults, stratigraphic features (i.e. onlap edges, channels and direct hydrocarbon indicators on horizontal data volumes) greatly surpasses what can be reasonably achieved on vertical data displays. We anticipate that interpretation and the study of horizontal seismic attribute and other signal enhancement displays will play an increasingly important role in the future subsurface mapping in Kuwait.

IPTC 11155 Specialized well log acquisition of formation elastic properties in support of 4-C surface seismic

Eduard Maili (Occidental), Scott Burns (Occidental), Tony Steele (Occidental), Pedro Romero (Occidental), William H. Borland (Schlumberger) and Taesoo Kim (Schlumberger)

Well logging programs are usually designed to measure petrophysical properties within the reservoir and the immediate surrounding formations. Rarely, if ever, is much of the overburden logged. As more sophisticated surface-measured geophysical methods are used, properties of the overburden are becoming more important. One method that is becoming more prevalent, 4C OBC seismic, can benefit from logging formations from surface continuously down to the reservoir. In preparation for the processing and interpretation of a major acquisition of 4C surface seismic run to illuminate a carbonate reservoir within Idd El Shargi North Dome field located offshore Qatar, a specialized logging program was devised and acquired on a well in the field to obtain formation elastic properties of compressional and shear velocities, including HTI anisotropy information, continuously from the seafloor down to the reservoir.

Particularly challenging was the acquisition of well logs and borehole seismic in the interval just below sea bottom. A drilling methodology was devised to allow a relatively small diameter pilot hole to be drilled and logged prior to reaming-out and setting surface conductor pipe. Logging tools were specially set-up such that continuous valid measurements would be made to acquire this expected low velocity and density interval. Other logging intervals were in zones difficult to log in openhole, and so cased hole contingencies were implemented. A "walkaround" borehole seismic survey was acquired in the reservoir section to obtain "reservoir-scale" anisotropy information comparable to surface seismic and was complimented with cross-dipole sonic log information, which is a more localized anisotropy measurement.

IPTC 11640 Seismic monitoring feasibility on Bu Hasa field

C. Marvillet (Total), C. Hubans (Total), P. Thore (Total), P. Desegaulx (Total), Y.S. Al-Mehairi (ADCO), M. Shuaib (ADCO) and Ali Al Shaikh (ADCO)

A 4-D seismic feasibility study has been performed on carbonate reservoirs of the Bu Hasa field, onshore Abu Dhabi. It concluded that method was feasibile as a reservoir injection monitoring tool, an interesting result when several recent papers have suggested that 4-D seismic may not be applicable to Middle East carbonate reservoirs due to their rock physics characteristics. 2-D full wave equation and 3-D convolutional modeling approaches have been combined in this study in order to maximize the reliability of the predictions while optimizing the cost effectiveness of the study. Because the assessment of repeatability noise indicated a realistically irreducible threshold for high-resolution 4-D surface seismic and a possible limitation for WAG monitoring, a 4-D well seismic exercise was simulated, which overcame those limitations.

IPTC 11437 Seismic attribute analysis: An aid in fracture play mapping

Srinivasa Rao Narhari (KOC), Nikhil Banik (KOC), Sunil Kumar Singh (KOC) and Talal Fahad Al-Adwani (KOC)

The Najmah and Sarjelu formations, corresponding to the Kimmeridgian-Bajocian stages, are established source rocks in the Middle East. Recent concerted and dedicated exploratory efforts in Kuwait have seen the successful upgrade of these formations into a potential reservoir rock because of the contribution from fracture-associated porosity. This paper examines the role of various seismic attributes in the identification of fracture corridors of this play. The data presented here are from the Raudhatain field and North West Raudhatain field areas of northern Kuwait.

Based on 3-D seismic data, a number of seismic attributes (such as coherency, edge, dip, dip azimuth and spectral decomposition) have been generated in the zone of interest to understand the distribution of the fault network, which in turn has helped in the identification of fracture corridors. The application of these attributes has highlighted the presence of minor lineaments, which have an impact on the fracture generation. The following methods were applied in generating the attributes: (1) window-based application along the seismic reflection event; (2) volume based application in the zone of

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interest; and (3) volume-based application parallel to the very strong Tithonian Gotnia salt reflector.

Integration of these attribute data sets has resulted in the generation of a detailed fault and lineament map of the area. Some of the attribute data were further refined by means of fault-tracking algorithms. Multi-volume visualization has helped in identifying areas with a higher probability of encountering fracture networks. Exploratory locations were selected based on the integration of these data sets and in structurally favorable locations. Subsequent drilling results have been very encouraging by encountering fractures according to expectations. The application of multiple seismic attributes has evolved into one of the primary drivers of success for this play.

IPTC 11275 Ontology-based warehouse time-depth data modelling framework for improved seismic interpretation in onshore producing basins

S.L. Nimmagadda (KOC), H. Dreher (Curtin University of Technology, Australia) and M.R. Rajab (KOC)

Time-to-depth conversion has been one of the objectives of seismic interpretation. There is no straightforward procedure that derives a depth section from a seismic section. This is due to the fact that seismic reflection times depend upon the positions and shapes of the reflecting interfaces. The velocity data patterns are often complex, affecting geological interpretations. Depth conversion takes considerable amount of an analyst's time and leaves concerns about its accuracy. This uncertainty in depth conversion procedure significantly contributes to pitfalls and ambiguities in depth conversion velocities. Ontology-based multidimensional modelling has been designed to address these concerns and offers an improved solution in time-depth conversion.

More than 150 wells with VSP data and ten key horizons were considered for computing time-structure maps in onshore basins. This was achieved through analysing seismic-times and sub-sea depths observed at well locations. Interactive QC of "seismic picks" at sub-sea depths, their velocity data patterns and correlations computed for multiple horizons for several well locations, provided a scope for improving structural anomalies. Seismic times, interpreted by horizon tracking at well locations, were compared with seismic times interpreted from VSP surveys. These entities and dimensions were documented and integrated in a warehousing environment. Organizing multiple reservoir data of hundreds of well locations in a warehouse environment and matching (and/or relating) time-depth dimensions at well locations that facilitate computing appropriate depth grids and deriving geological interpretations, are key highlights of this paper. This modelling procedure minimizes the ambiguity involved in time-depth conversion and imaging for better structural interpretation. Data mining among several variable attributes signified interesting velocity trends that helped us construct linear equations among varying attribute properties. Ontology-base-warehouse modelled time-depth data provided a good match between computed depths and actual well tops at well locations, besides interpolating and extrapolating depth values away from wells.

IPTC 11305 Evaluation of deep, low frequency acquisition techniques on deep target imaging

Michael W. Norris (ExxonMobil) and Marvin L. Johnson (ExxonMobil)

A suite of air-gun configurations was tested in the Gulf of Mexico using a MEMS-based OBC acquisition system. One advantage of this acquisition system was the significantly improved low-frequency response of the sensors and instrumentation. The improved low-frequency response allowed the response of the air gun configurations to be characterized to 1 Hz and below. The data from the various air-gun configurations were analyzed by comparative analysis between the air-gun configurations, by analyzing the phase coherence within each of the tested configurations and by examining low-passed versions of brute stacks. The results from the three methods appear to support one another with the conclusion being that conventional air-gun sources generate recoverable energy above 5 or 6 Hz. In the area where the test was conducted, coherent energy from the air-gun sources could be identified at 11 to 12 seconds TWT for frequencies above 6 Hz.

IPTC 11325 The road to efficient wide-azimuth high-density 3-D land vibroseis acquisition

J.J. Postel (CGGVeritas), J. Meunier (CGGVeritas), T. Bianchi (CGGVeritas) and A. Depeyras (CGGVeritas)

It is becoming increasingly widely accepted that wide-azimuth 3-D acquisition is the best way to improve imaging of complex and subtle traps. It is also claimed that high-density point source/point receiver acquisition constitutes the ultimate seis-

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mic acquisition technique. Clearly, both techniques require a considerable increase in equipment and density of both source and receiver points. How much is still a matter of debate. Currently most 3-D vibroseis crews use two fleets of vibrators in flip-flop mode. The productivity depends on the sweep length and the time it takes to move from one VP to the next. The slip-sweep technique is an attractive way of optimizing productivity to a level that can keep the cost of increasing source density within reasonable limits. The productivity increase with this technique is linked to a new parameter called the "slip-time" (the minimum time interval between two consecutive VPs). In the real world, nothing is free and the price to be paid is that the data can be severely contaminated by harmonic noise due to the use of long sweeps combined with a very short slip-time. To overcome this problem, a method of harmonic noise reduction known as "High-Productivity Vibroseis Acquisition" (HPVA) has been developed. This method consists in estimating the harmonic noise in the vibroseis signature so that it can be subtracted. Several crews are now routinely using this technique with three to four fleets of vibrators. Recent 3-D tests with 12 fleets of single vibrators also showed very promising results, which will be presented. Combined with a densification of the source grid, single-vibrator acquisition can bring either an improvement in data quality or an increase in productivity and opens the road to affordable dense, wide-azimuth seismic acquisition in desert environments.

IPTC 11407 The Role of seismic coherence attributes in mapping the fracture network and improving the productivity from thick, tight and fractured deep gas reservoir

Naji A. Qassim (BAPCO), Abdulla Jaffar Al-Anaisi (BAPCO) and Ali Ebrahim Al-Muftah (BAPCO)

This paper describes an integrated study of utilizing 3-D seismic, open-hole logs with simulation, pressure transient analysis and production data to define and map fracture network patterns to aid enhance the productivity from thick, tight and fractured deep gas-bearing carbonate reservoir in the Awali field, Bahrain. The Lower Permian Khuff K3 zone is a thick, tight, highly faulted and irregularly fractured carbonate reservoir. The massive 800-ft-thick reservoir with very low average permeability of the order of 1 mD, poses challenge in efficient recovery of hydrocarbons. The present production from this reservoir accounts for less than 10% of the total gas production from the Khuff Formation of the field. This has prompted a detailed integrated study to help enhance the well productivity. It is well known that seismic coherence data plays a pivotal role in defining and mapping fracture network, and similarly, well testing leads to an understanding of the reservoir dynamics and connectivity. The approach involves identification of fracture network from seismic data and validating them with transient well testing and production data at and around the well-bore. The study was applied to derive and input fracture network and related data of the Khuff K3 zone into the simulation model to define and map the reservoir fracture patterns to aid in increasing productivity and also recovery.

IPTC 11457 Wamsutter's integrated seismic program-transforming land seismic, from data acquisition through interpretation and analysis

Rosemarie T. Ramkhelawan (BP), William Alan Hicks (BP), Colin T. Bruce (BP), Craig W. Cooper (BP), Brian Hornby (BP), James A. Hornbeck (BP) and Ricko Wardhana (BP)

The US Onshore Wamsutter Field Development Team executed two seismic field trials in 2006: a borehole seismic field trial and a cableless surface seismic field trial. The borehole seismic field trial consisted of a 4-well cross-well tomography program, and acquisition of a massive 3-D VSP with 8,000 ft of 3C receiver tool deployed in the well bore and 6,000 surface vibroseis source points. The surface seismic field trial is the world's first deployment of the FireFly cableless seismic acquisition system, with 8,300 3C digital sensors deployed, and 7,200 explosive source points. These field trials were designed to increase seismic resolution, improve imaging and identification of higher porosity zones, and increase fault and fracture detection, with the ultimate goal of optimizing field performance. The data that was previously available for interpretation had a dominant frequency of 25 Hz, which allowed us to image reservoir thicknesses of greater than 50 ft. The producing reservoirs have much lower average thicknesses, which have been targeted with the new higher resolution cross-well, 3-D VSP and dense surface seismic data.

Rock properties understanding of the Wamsutter reservoirs has been fundamental to well-to-seismic calibration and interpretation and analysis of the seismic datasets. Seismic forward modelling has been undertaken to calibrate the seismic responses, as part of a larger integrated effort to understand porosity and lithology responses and fracture anisotropy. Field acquisition presented many challenges that were safely and successfully overcome.

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The cross-well data has resolved reservoir thicknesses of less than 20 ft. Frequencies from the 3-D VSP are better than historically recovered in surface seismic data. This integrated borehole/surface seismic approach has allowed us to better understand the seismic responses and calibrate rock properties to different levels of seismic resolution. The Wamsutter Seismic Field Trials is a true success story worth sharing globally.

IPTC 11715 Step change in 3-D two-component OBC seismic imaging in the Arabian Gulf

J.M. Reilly (ExxonMobil), A. Shatilo (ExxonMobil), M. Rainwater (ExxonMobil) and Hamad Bu Al-Rougha (Zakum Development Company)

The common industry approach to the processing of 3-D, two-component (2C), Ocean Bottom Cable (OBC) data includes summing the hydrophone and geophone sensors at an early stage of the processing sequence. In this study, we demonstrate that a step change in seismic imaging quality has been achieved on a shallow-water Arabian Gulf dataset via completely separate processing of the hydrophone and geophone data through CMP stack. The results of this work are compared with those obtained using more conventional approaches.

The primary utilization of the vertical geophone sensor in a conventional two-component OBC processing flow is in the mitigation of receiver-side reverberation. However, the noise generated in a variable-depth, shallow water environment often contains both source- and receiver-side reverberation modes that are not sufficiently reduced by conventional hydrophone-geophone summation techniques. The underlying physics of surface-wave ("mud roll") and water column trapped-wave modes detected by geophone and hydrophone sensors are quite different and do not necessarily conform to the assumptions in current processing methods. Geophone motion in particular may be quite complex. The effectiveness of sensor (2C) summation techniques is highly dependant upon extracting accurate scaling parameters from the data and proper spectral matching of the hydrophone and geophone records. Residual noise in the data may affect both the scaling/matching processes as well as 2C summation itself. It is commonly observed that raw vertical geophone OBC data contain more noise than the hydrophone. Inadequate noise attenuation before 2C summation often leads to "over-weighting" of the hydrophone data or, worse, discarding the geophone data entirely.

Previous work has demonstrated that improved imaging can be obtained via separate application of adaptive noise-suppression techniques prior to sensor summation. The fundamental principle in this study is that the highest signal-to-noise ratio is generally achieved in the latest stages of the processing sequence (in this case post CMP stack), which appears to be the optimal stage for sensor summation. This not only allows for an optimal combined image but also for creation of separate images of each component. The separate OBC hydrophone and geophone images may be used in a workflow that allows one to distinguish between residual noise and primaries. The results of this study are consistent with previous work on four-component OBC data.

IPTC 11204 Multi-azimuth streamer acquisition: Initial data analysis

W. Rietveld (BP), J. Keggin (BP), M. Benson (BP), T. Manning (BP), A. Burke (PGS) and A. Halim (PGS)

A thin but complex layer of partially eroded anhydrite and other facies lie at a depth of around 3 km across large areas of the Nile Delta in the Mediterranean. Wavefield distortion, attenuation and the generation of complex multiple diffraction noise cause the quality of the underlying seismic image to be highly variable. Multi-azimuth (MAZ) seismic can help resolve these issues and improve the deep pre-Messinian image. Here we discuss the processing flow and initial data analysis of a MAZ streamer dataset. The main elements of the flow used are a standard streamer demultiple followed by Kirchhoff post-stack time maigration (PSTM). The initial data analysis shows that MAZ greatly improves general image quality, signal-to-noise ratio and lateral resolution, and suppresses diffracted and other multiples effectively, despite some of the obvious limitations of the processing flow. Issues and challenges around this approach are discussed.

IPTC 11359 Prediction of thin bed reservoirs below 1/4 wavelength tuning thickness using full bandwidth inverted seismic impedance

Michael L. Shoemaker (BP), Jeff B. Robinson (BP), Philip N. Trumbly (BP) and Bob A. Brennan (BP)

Although conventional 3-D reflection seismic data has been invaluable in the exploration and development of oil and gas fields worldwide, the standalone technology fundamentally lacks the resolution required to adequately characterize complex, thin-bedded hydrocarbon reservoirs. Limited vertical

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seismic resolution, implicitly defined at the "wavelength tuning thickness", can become particularly problematic when predicting reservoir dimensions, and ultimately for risk and reserve evaluation. Widess (1973) observed that thickness estimation of a "thin-bed", below the wavelength tuning thickness, can be detected (or is encoded) within the amplitude of the composite amplitude, which results from the increasing constructive interference of the top and base reflections as the bed thins. Herein, a methodology is introduced whereby aggregate reservoir sandstone thickness is successfully predicted away from well control via full bandwidth (0 to 25 Hz) inverted seismic impedance.

Thin-bed reservoir thickness prediction utilizing inverted seismic impedance has been successfully applied in the onshore Tuscaloosa deep gas (7,000 m) trend located in Louisiana, USA, where gross reservoir sandstones less then 40 meters thick are below the tuning thickness. Well logs from 120 wells were used to regionally calibrate the 3-D seismic cube to subsurface stratigraphy. A precise calibration allows for accurate rock property and seismic stratigraphic analysis, and tuning-wedge-type modeling; the results of which confirm that seismic amplitude response at Tuscaloosa is true to tuning phenomena, rather than rock property/fluid saturation effects. The 3-D full bandwidth inverted seismic impedance data were linearly transformed to a sandstone thickness cube (in meters) well below the tuning thickness, thus doubling seismic thickness prediction by at least an order of magnitude. This technique has resulted in accurate gross sandstone thickness estimation, and ultimately improved volumetrics for risk analysis and reserve estimations.

IPTC 11418 Impact of reservoir pressure changes on 4-D seismic responses in carbonates: Special rock physics core study

W.L. Soroka (ADCO), T. Al-Dayyani (ADCO), Christian J. Strohmenger (ADCO), H.H. Hafez (ADCO) and M. Al-Jenaibi (ADCO)

A rock physics core study was successfully conducted to investigate the effects different fluids and reservoir pressure changes have on the velocity of carbonate rocks. Eighty vertical core plugs representing all reservoir and non-reservoir facies over a Cretaceous interval of interest were selected for use in this study. Dense non-reservoir facies with low porosity and permeability showed minor to no velocity changes to pressure changes. The velocity of reservoir facies with significant porosity and permeability were observed to change with fluid type, effective pressure and porosity. Samples with higher porosity and more heterogeneity showed the most velocity change with pressure. Based on the ultrasonic velocity results, saturation changes will produce larger velocity changes than pressure changes in the reservoir. The results of this rock physics core study are helping in the interpretation of 4-D seismic responses in carbonates. Observed 4-D seismic anomalies are more likely the result of saturation changes and less likely to be related to reservoir pressure changes. 4-D anomalies can be produced by reservoir pressure changes but should be lower magnitude than those related to saturation changes. Large 4-D anomalies linked to pressure are more likely due to a significant pressure increase, related to high-pressure injection.

IPTC 11436 3-D Seismic attributes applied to carbonates to detect small faults and potential fractures: A case study from Kuwait

Ismail Mohammed Syed (KOC) and Bader Al-Ajmi (KOC)

In general it is difficult to map minor faults and other trace-to-trace discontinuities hidden in 3-D seismic data, which has direct bearing on proper reservoir description. Often these subtle faults and discontinuities appear as minor changes in the seismic waveform, which are not easily correlatable and difficult to map by conventional interpretation techniques. To map these relevant 3-D seismic attributes that are sensitive to subtle faults and fractures has been investigated in the target reservoir, the Early Cretaceous (Albian) Mauddud Formation of Raudhatain field in northern Kuwait. The giant Raudhatain field is a faulted anticlinal dome having two sets of faults and produces from reservoirs in the Zubair, Burgan and Mauddud formations. Our main objective was to better understand and predict the possible fractures in the Mauddud reservoir to improve the structural framework for effective future planning of development and injector wells.

Major faults are easily identified at the top and base of the Mauddud Formation due to large acoustic impedance contrasts between Mauddud and clastic units of the overlying Wara and underlying Burgan formations. Smaller faults and possible fractures within Mauddud are difficult to map due to the lack of vertical resolution and poor signal-to-noise ratio within the reservoir interval. To overcome this problem various 3-D seismic attributes were computed and investigated. Horizon- and volume-based attributes (dip and azimuth, curvature, shaded relief, spectral decomposition and coherency) were used and integrated with subsurface data to arrive at the best possible structural framework of the reservoir.

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IPTC 11614 3-D Seismic in the mature onshore Dukhan field: What is the value of new seismic data?

Andrew Brodie Thomson (QP), Peter Van Baaren (QP), Hussain Al-Ansi (QP) and Andrew Smart (WesternGeco)

3-D seismic data is recognized as a key tool in successful reservoir management. The existing Dukhan 3-D seismic data is more than 15 years old and is of poor quality. 3-D seismic technology has advanced significantly in the last 15 years and the technical case for new data appears to be strong. However, in a mature field with more than 700 wells, the potential business impact of new 3-D seismic data needs to be carefully evaluated. Qatar petroleum (QP) undertook a seismic feasibility study in 2003 and concluded that the technical and business impact of new data needed to be tested before any larger scale full-field re-shoot could be considered. To address this issue, a state-of-the art combined borehole and 50 square km surface seismic pilot 3-D survey was acquired over Dukhan field in 2006. The purpose of the pilot survey was to assess the technical benefit of new acquisition and to assess survey design issues. Additionally the pilot 3-D seismic survey allowed QP to get a much better assessment of the many logistical issues involved with shooting land 3-D within an active producing oil field. This Dukhan pilot 3-D seismic survey successfully highlights the dramatic impact of the many advances in seismic technology over the last 15 years The paper discusses the technical needs to be addressed by new seismic data, the acquisition and processing results, compare the new data with the old data and discuss the impact of the pilot data on plans for larger full field re-acquisition.

RESERVOIR CHARACTERIZATION

IPTC 11115 Reservoir optimization and monitoring: Mauddud Reservoir, Awali field, Bahrain

Ali E. Al-Muftah (BAPCO), William Vargas (Schlumberger), C.R.K. Murty (BAPCO) and Ayda Abdulwahab (BAPCO)

For a matured oil field like Awali field, with a long production history, it is required to identify under-performing areas, infill wells and upgrade the reserves. This paper describes the application of a practical process as follows: (1) to develop systematic workflow for production optimization and reservoir analysis; (2) identify and highlight reservoir trends, patterns and anomalies; (3) identify and highlight the under-performing wells/areas and recommend solutions, and (4) identify essential patterns for consideration in an overall development plan. It is required to quickly adopt assessment methods for such a mature field. The area used for the study consists of 431 wells in the Mauddud reservoir, which is one of the major producing zones. The challenge was to evaluate large data sets in a short time and cost-effective manner.

The technique uses a streamlined workflow of reservoir assessment processes, which require a sequence of data gathering, formatting and validation through combining the data with several processes associated with both the static and the dynamic models of the reservoir. Quick interpretations of these models generate opportunity regions, re-completions and workover candidates, and new infill potential in the reservoir. Based on the processes run in the Mauddud zones, it was possible to understand rapidly the reservoir performance and main issues associated with field development (water production, gas injection, potential transfer areas). In addition, under-performing wells/areas and potentially undrained areas (high remaining reserves zones with low water cut and low gas/oil ratio) were identified with certainty in a timely manner. As a result of these techniques, the developmental drilling program was suitably adopted to achieve an efficient reservoir management process for developing the field and helped in decreasing decline rate and increasing the recovery.

IPTC 11191 The control of fracturing and dolomitisation on 3-D reservoir property distribution of the Asmari Formation (Oligocene-Lower Miocene), Dezful Embayment, southwest Iran

Adnan A.M. Aqrawi (StatoilHydro) and Ole Petter Wennberg (StatoilHydro)

The Asmari Formation (Oligocene-Early Miocene) is the most important reservoir in the oilfields in the Zagros foreland of the Dezful Embayment of southwest Iran. The carbonate reservoirs of the Asmari Formation are characterized by low matrix permeability, and effective drainage is dependent on the occurrence of open fractures. The fractures formed during the Zagros Orogeny since Late Miocene, which was also responsible for the geometry and formation of NW-trending anticlinal traps. Dolomitisation is another factor controlling reservoir quality as dolostones, in general, have higher porosities than limestones.

The fractures are typically stratabound and sub-per-

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pendicular to bedding. The density and dimension of fractures are controlled by the mechanical stratigraphy, which is controlled by the depositional environment and cycles. In the platform top sequence, Dunham's (1962) texture classification appears to be the most important factor controlling the Fracture Intensity (FI) rather than the mechanical layer thickness. Mud-supported textures (mudstone and wackestone) have higher FI than grain-supported ones (packstone and grainstone). The fracture density is high in the vicinity of faults. Two main types of dolomite fabric are recognised; finely crystalline pervasive dolomite (< 20 microns) replacing mud-rich facies; and combinations of finely crystalline replacive dolomite surrounded by coarser dolomite cement (up to 100 microns) in grain-supported facies. Dolomites have an evaporitic signature, based on geochemical and petrographic data, with a general upward increase in the abundance of both anhydrite and dolomite. Dolomite replacing the mud-dominated facies occurs as thinner beds, less extensive aerially forming the top of stratigraphic cycles deposited during highstand, and has lower reservoir quality, particularly as microporosity. In contrast, dolomite replacing the grain-dominated facies exists in thicker and more extensive beds forming the bottom of stratigraphic cycles deposited during early transgression, and these have better reservoir quality, particularly if leached or coarsely crystallined.

IPTC 11247 An overview of reservoir quality in producing Cretaceous strata of the Middle East

S.N. Ehrenberg (StatoilHydro), Adnan A.M. Aqrawi (StatoilHydro) and P.H. Nadeau (StatoilHydro)

A compilation of average porosity and permeability data for Cretaceous petroleum reservoirs of the Middle East reveals important differences between the two main tectonic provinces present in this region. The Arabian Platform tectonic province is characterized by strong inverse correlation of average porosity with present depth in both carbonates and sandstones, whereas the Zagros Fold Belt, containing almost exclusively carbonate reservoirs, has distinctly lower porosity overall and no porosity-depth correlation. These contrasts are interpreted as reflecting the fact that Arabian Platform strata are mostly at or near their maximum burial depth, whereas Zagros strata have experienced widely varying uplift and erosion following maximum burial in mid-Tertiary time. The carbonate reservoirs show no correlation between average porosity and permeability, probably because of wide differences in dominant pore types. Average permeabilities tend to be much higher for sandstones than for carbonates, despite similar porosity for given depth.

Existence of the Arabian Platform porosity-depth correlation, despite wide diversity of depositional settings and early diagenetic porosity modifications among the individual component reservoirs, reflects the overriding importance of burial diagenesis in controlling the porosity differentiation of reservoir rock bodies. Although porosity commonly shows enormous small-scale (bed-to-bed) heterogeneity, the average pre-burial porosity of larger stratigraphic intervals tends to be very high in both carbonates and sandstones. Burial diagenesis progressively destroys this porosity by chemical compaction and associated (stylolite-sourced) cementation, such that all portions of the affected rock body move toward the zero limit as depth increases. Average reservoir porosity therefore tends to correlate inversely with depth, regardless of the complexities of depositional facies and early diagenesis.

IPTC 11763 Characterization and modelling study of a triple porosity fractured reservoir

F. Gouth (Total), L. Moen-Maurel (Total), F. Jeanjean (Total), C. Soyeur (ADMA-OPCO) and Sabah K. Aziz (ADMA-OPCO)

An integrated, multi-disciplinary, fracture characterization and modeling study has been performed on a large oil reservoir in offshore Abu Dhabi. This paper describes the methodology used for analyzing and integrating the geophysical, geomechanical, geological and reservoir data in order to achieve a comprehensive understanding of the fracture network and its effect on fluid flow. The study has highlighted the existence of two scales of fractures in this reservoir, which form a triple porosity system in regions where they are interconnected. The first consists of diffuse fractures, which strike N20^{o} to N40^{o}. This scale develops mostly in the denser reservoir units. Its spacing is controlled by the mean curvature of the seismic top- reservoir surface and by the structural depth. On the crest, it forms a connected network of a few tens of mD of equivalent permeability, i.e. about 10 times the matrix permeability. The second consists of large-scale fractures forming a connected network on the crest of the structure. They are associated with N30^{o} corridors and N90^{o} to N140^{o} trending faults yielding an equivalent permeability of a few hundreds of mD, which is highly anisotropic with a main axis consistent with the maximum horizontal stress azimuth.

The work is based on intensive use of 3-D seismic imaging to characterize the spacing of the large

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scale fractures, which were poorly sampled by the existing wells. Advanced use of pressure build-up and interference tests were used to characterize the fracture permeability field, i.e. average value, anisotropy ratio and extension. The diffuse fractures were modeled using a discrete fracture network. The drivers (depth and curvature) used for the populating of the diffuse fractures in the full-field model were also used for the large-scale fractures since data suggest that both scales develop in the same areas. A strategy is proposed to lump together the two fracture scales in a dual-porosity, dual-permeability reservoir model. The resulting dynamic model was easily history matched and required only slight adjustments.

IPTC 11722 Improved characterisation and modelling of carbonate reservoirs for predicting waterflood performance

S.K. Masalmeh (Shell) and X.D. Jing (Shell)

Carbonate reservoirs are highly heterogeneous and often show oil-wet or mixed-wet characteristics. Both geological heterogeneity and wettability have strong impact on capillary pressure (Pc) and relative permeability (Kr) behaviour, which is controlled by the pore-size distribution, interfacial tension and interactions between rock and fluids as well as the saturation history. Capillary pressure data are essential input in both static and dynamic modelling of heterogeneous carbonate reservoirs. Drainage Pc is generally used for initializing reservoir static models, while imbibition Pc is used to model secondary and tertiary recovery processes.

The objective of this paper is to present an improved reservoir characterisation and modelling procedure for predicting water flood performance of a Cretaceous carbonate reservoir in the Middle East. We focus on the characterisation of multiphase fluid-flow properties, in particular the capillary pressure characteristics in both drainage and imbibition, and their assignments in reservoir simulation models. We show that for modelling initial saturation distribution in the reservoir, assigning saturation functions based on permeability or porosity classes alone is not adequate. Moreover, the petrophysical correlations often used for clastic reservoirs (e.g. Leverett J-function) may not be applicable to carbonate reservoirs without careful pore-type examination and core analysis/calibration.

A novel procedure is described to derive imbibition capillary pressure curves from the primary drainage Pc curves taking into account of wettability and fluid trapping. The results lead to an improved understanding of capillary pressure characteristics in carbonate reservoirs, in particular, the contact angle distributions and hysteresis behaviour in both drainage and imbibition. This paper also presents a mathematical model for implementing both drainage and imbibition capillary pressure functions in dynamic reservoir simulation. This model takes into account the complex pore size distribution and wettability characteristics in carbonates as observed in experimental special core analysis (SCAL) measurements. Furthermore, how to assign imbibition Pc for the different porosity and permeability classes will be examined and its impact on modelling waterflooding performance and remaining oil saturation distributions assessed.

IPTC 11219 The Jurassic-age Marrat Reservoir at Humma field, Partitioned Neutral Zone (PNZ), Saudi Arabia and Kuwait: Utilization of a probabilistic, two-stage design of experiments workflow for reservoir characterization and management

W. Scott Meddaugh (Chevron), David Barge (Chevron), W.W. (Bill) Todd (Chevron) and Stewart Griest (Chevron)

The Jurassic-age Humma Marrat carbonate reservoir is mainly located in the southwest corner of the Partitioned Neutral Zone (PNZ) between Saudi Arabia and Kuwait. The reservoir was discovered in 1998. The reservoir depth is about 9,000 ft sub-sea. The gross reservoir interval is approximately 730 ft thick (110 ft net). The lowermost Marrat E zone contributes 80–90% of the production based on PLT data. The productivity of the Marrat E is dominated by a forty-foot thick, largely dolomitized interval with 15-20% porosity and 20–100 mD permeability. The upper zones contribute 10–20% of the production from thin intervals with 12–15% porosity and 2–5 mD permeability.

A two-stage design of experiments (DoE) based workflow was used to evaluate and optimize primary reservoir development. Reservoir uncertainties affecting volume and connectivity were assessed in the first stage of the workflow. The second stage of the workflow focused on dynamic uncertainties. The results of the workflow defined the P10, P50, and P90 models used for development optimization. Economic analysis showed that 640-acre primary development using vertical wells was the most attractive option. Pressure data obtained during field delineation in 2005 and 2006 showed the reservoir to be approaching bubble point pressure in the Marrat E zone main compartment. Ongoing dynamic modeling showed that only a limited number of additional wells were needed and the primary development project scope decreased considerably.

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Data acquired during delineation drilling in 2005 and 2006 continued to reduce reservoir uncertainties. Additional dynamic simulation was done in 2006 to refine development options. Rather than redo the entire DoE-based workflow, a series of dynamic models were generated in 2006 that incorporated the new well data and preserved the capability of giving probabilistic results. The modified DoE approach was shown to be an efficient tool for final assessment of primary development options and reserves.

IPTC 11794 Integrated local reservoir connectivity analysis in a channelised turbidite reservoir

Asghar Shams (Heriot-Watt University, UK)

A good understanding of reservoir performance for management and production requires information on the pressure and saturation variations together with the major connected paths in the system. However in complex geological settings such as channelised turbidite sands, the pathways for fluid movement and pressure evolution between the individual sand bodies are not obvious and cannot be easily inferred from geological data. The effect of gas/water injection and production is therefore hard to predict with certainty. To address this problem, a method that integrates both time-lapse seismic data and a well interference test is developed to help provide a local update to the reservoir simulation model. The benefit is derived from the overlap between the aerial resolution of the time-lapse seismic with the harder, more localised pressure data from the well test. The seismic contributes to an understanding of the 3-D geometry of the connected bodies, and this information is fed into an inversion of the well test data to help reduce the non-uniqueness in the interpretation and improve stability. The technique is successfully applied to a deepwater turbidite reservoir with satisfactory results.

IPTC 11201 Identifying fluid type and contacts in carbonate reservoirs

Hsin-Yi Tseng (ExxonMobil), Robert J. Pottorf (ExxonMobil), Duncan Mardon (ExxonMobil) and Paul J. Mankiewicz, (ExxonMobil)

Present-day fluid type and contacts in carbonate reservoirs can be difficult to determine from standard formation evaluation techniques because of complex rock properties and variable fluid compositions. In such situations, integrating novel rockbased geochemical analyses of adsorbed and inclusion-trapped fluids helps reduce fluid contact uncertainty and evaluate the probability of various fluid types. The rock-based analyses include three techniques that can be applied to either core or cuttings samples. First, volatile compounds adsorbed or trapped in pore spaces are measured by mass spectrometry using a patented pumpdown volatiles (PDV) technique. Second, fluid inclusion volatiles (FIV) analysis also uses mass spectrometry to characterize volatile compounds released from fluid inclusions when samples are crushed. Both analyses are rapid and inexpensive and therefore are frequently applied to entire wells to allow stratigraphic correlation of responses for mapping fluid types and contacts. However, because FIV signatures include both present and paleo fluids, additional analyses are needed when filling history is complicated (e.g. gas displaces oil). For example, PDV and FIV interpretations can be confirmed and refined with a third technique, thermal desorption gas chromatography/mass spectrometry, Iatroscan, and/or Rock Eval pyrolysis. In addition to these analytical techniques, a statistical modeling tool has been developed for quantitative probability predictions of reservoir fluid type from complex FIV and petrophysical signatures. The model is constructed by calibrating FIV and petrophysical data to known test results, and then applying it to predict fluid type in wells where test results are absent or ambiguous. Besides providing an integrated approach to fluid type and contact evaluation, this tool allows multiple scenarios and quantification of uncertainty. This paper summarizes methodologies and key applications of rock-based techniques for accurate resource evaluation, improved completion decisions, and optimized exploration, development, and production strategies in carbonate reservoirs.

IPTC 11199 Reactive transport models of limestone-dolomite transitions: Implications for reservoir connectivity

Yitian Xiao (ExxonMobil) and Gareth D. Jones (ExxonMobil)

Substantial volumes of world hydrocarbon resources occur in interlayered limestone-dolomite reservoirs. Diagenetic variations in lithology and primary depositional texture control the magnitude and spatial distribution of petrophysical properties. The frequency and nature of limestone-dolomite transitions that define flow units and baffles/barriers are critical for understanding reservoir connectivity and optimizing field development. Existing subsurface predictions are largely based on observation and are occasionally linked to sequence stratigraphy. This approach can be relatively successful at predicting general trends in limestone and dolomite occurrence, but there is considerable uncertainty in predicting and correlating spatial

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variations in diagenetic styles at the field scale.

Reactive transport models that explicitly couple fluid flow and chemical reactions to facilitate quantitative investigations of limestone-dolomite transitions are a recent addition to the predictive diagenesis tool kit. The approach is illustrated with a generic study designed to investigate the fundamentals of brine reflux dolomitization. Results provide new insights on: (1) dynamic propagation of limestone-dolomite fronts by fingering, (2) the connectivity of dolomite 'fingers' to the 'main body'; (3) dolomitization and anhydrite occurrence (primary precipitation and cements); (4) locating reservoir 'sweet spots' in a dolomite geobody; and (5) the interaction and importance of semi-regional versus local brine reflux flow. This process-based approach, in combination with available observational data and sequence stratigraphic paleoenvironmental reconstructions, has significant implications for predicting limestone-dolomite transitions, the spatial distribution of petrophysical properties and viable realizations of reservoir connectivity for flow simulation.

PRODUCTION CASE STUDIES

IPTC 11660 Well stimulation technology for thick, Middle East carbonate reservoirs

I.S. Abou-Sayed (ExxonMobil), C.E. Shuchart (ExxonMobil), N.H. Choi (ExxonMobil), B.M. Clancey (RasGas, Qatar) and T.F. Bene (RasGas, Qatar)

Previously, ExxonMobil had undertaken a multidisciplinary approach to develop and integrate the required technologies for design, implementation, and evaluation of acid treatments in thick heterogeneous carbonate reservoirs. RasGas, in collaboration with ExxonMobil, has customized the technologies and integrated methodology for application in a major field in the Middle East with a high level of success. Acid placement and diversion are critical to achieving effective stimulation in heterogeneous carbonate reservoirs. While permeability is a major factor in the distribution of acid along a completion for many reservoirs, pre-stimulation skin damage, intermixed rock types with different acid-rock wormholing characteristics, distance between zones, and differential reservoir depletion also play important roles in the effective stimulation of the reservoirs. Important steps in the integrated methodology developed and implemented for matrix acidizing include: (1) determine the stimulation requirements given the well/reservoir objectives; (2) characterize the various rock types present in the formation; (3) develop an integrated perforation/stimulation strategy; (4) conduct appropriate laboratory tests with representative field core plugs; (5) model the stimulation process with tools calibrated to the formation of interest; (6) develop field procedures and implement the treatments as per design; (7) evaluate stimulation effectiveness; and (8) optimize treatments based on post-stimulation performance and operational constraints. This paper features some of the technologies that have been developed and describes the integrated methodology used to effectively stimulate thick carbonate reservoirs in the Middle East.

IPTC 11415 Relative permeability measurements and analyses for a cluster of fields in South Oman

Mohammed Al-Gharbi (PDO), Xudong Jing (Shell), Martin Kraaijveld (PDO), Jon Hognestad (PDO) and Pius Udeh (PDO)

During a large water flood study on a cluster of fields in southern Oman it became apparent that relative permeability constituted one of the major uncertainties impacting reserves in the cluster. At the onset of the study, only two experimental measurements were available that had been acquired with the currently recommended approach of wettability restoration and a combination of steady-state and centrifuge experiments. Therefore, the team proposed to core five wells and embarked on a large-scale special core analysis (SCAL) program, covering all predominant rock types, in order to get a better handle on the relative permeability characteristics.

This paper presents a case study of using a properly measured set of relative permeability data to replace the previously used analogue database and hence reduce uncertainties of water flood recovery predictions. The experimental programme followed a recommended procedure of wettability restoration and a combination of steady-state and centrifuge experiments. When the experimental data became available, they were reviewed and numerically interpreted using the state-of-the art simulation techniques.

This has led to several insights that were missed in earlier field studies, which used a set of simplified correlation functions/parameters for the cluster of fields without adequate special core analysis data calibration. Based on the new results the field's relative permeability characteristics were divided into two categories linked to rock types thus significantly reducing the uncertainty range. In this paper we also highlight the procedure that was used to generate the new SCAL experimental da-

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taset and the analysis that has been done to arrive at this conclusion. The simulation effort and the subsequent analysis have reduced the uncertainty in relative permeability by a factor of three resulting in a significant improvement in the robustness of the development plans.

IPTC 11396 The design of the first miscible sour gasflood project in Oman

Abdullah Al-Hadhrami (PDO), Darrell Davis (PDO), Geurt Deinum (PDO) and Harry Soek (PDO)

This paper summarizes parts of the strategies that were developed to demonstrate the feasibility of the first miscible sour gas injection project in one of the reservoirs of a cluster of fields in southern Oman. The hydrocarbons in the cluster are contained in carbonate "stringers", which are approximately 100 m thick slabs of carbonate floating within salt at depths between 2.5 km to 5 km. Large quantities of sour gas with 3–4% H_2S and 10–15% CO_2 are available to be used as miscible agents. The cluster is developed in a phased manner. The key objective of phase one, producing via primary depletion, was to gather data from a number of different reservoirs to determine whether a miscible gas-injection project is feasible. A balance between early delivery of new oil and the complex subsurface appraisal that takes resources and time is necessary. An example of a workflow that led to the construction of static and dynamic reservoir models with different realizations in one of the fields is described. This includes 3-D seismic, well test and PVT data, well logs, correlations and interference testing. Advanced technologies have been utilized to monitor reservoir performance from Phase 1 and to forecast predicted oil recoveries for the miscible gas injection projects. The collection of production data and pressure performance along with appraisal drilling have provided valuable information to allow the reservoir models to be updated. It is illustrated that the emerging data can lead to subsurface concept refinements, which have been included in the project design. The subsurface strategies are described as to how the information has been incorporated in the detailed facility design for this first miscible sour gas injection project in Oman.

IPTC 11234 Review of and outlook for enhanced oil recovery techniques in Kuwait oil reservoirs

Saad F. Alkafeef (College of Technological Studies, Kuwait) and Alforgi M. Zaid (College of Technological Studies, Kuwait)

In this paper, we carried out an updated investigation of enhanced oil recovery (EOR) applications in Kuwait. The investigation employs EOR screening analysis to determine the suitability of EOR processes to mature oil reservoirs. Following the determination of the suitable EOR process, we performed incremental recovery (IR) calculations. We also performed a preliminary economic analysis to determine the economic feasibility of the EOR processes in question. The screening analysis revealed that CO_2 and other miscible processes would have wide applications in these mature oil reservoirs. Polymer, surfactant/polymer, and alkaline flooding processes would also be widely applicable. In some cases, the polymer and surfactant/polymer processes were not suitable due to high reservoir temperature. Some of the important oil reservoirs have shown to be suitable for the application of thermal recovery processes, particularly steam injection.

A relatively new injection method known as steam-assisted gravity drainage (SAGD) appears to be viable for enhancing heavy oil recovery from the oil reservoirs containing heavy oil. These reservoirs are thick fractured layers, which can be good candidates for drilling horizontal wells where injected steam chambers can contact large volumes of oil. The presence of fractures may present a conduit for steam to cover a large volume pore space.

The incremental recovery calculations indicated that the additional recovery is 10–12% for miscible, 4–5% for polymer, 20–22% for surfactant/polymer, all of which refer to percentage of original oil in place (OOIP) in addition to water flooding. The fractional recovery due to the application of steam injection (SAGD) could be as high as 50% of the OOIP for the reservoirs containing the heavy oil. The economic analysis revealed that the oil market environment is favorable for the application of EOR processes in Kuwait where reservoirs are thick and contain huge oil volumes.

IPTC 11240 Case study: Integrated study for assessing production enhancement from a matured large carbonate reservoir

Eisa Al-Maraghi (KOC) and Cholamcottu V.G. Nair (KOC)

An integrated study has been conducted to build a reservoir management tool to evaluate enhancing the production and maintaining a plateau for the Umm Gudair field, a large carbonate reservoir located in Kuwait and the Partitioned Neutral Zone. The lower Cretaceous Minagish Oolite is the primary producing horizon in the field and is one of Kuwait's largest carbonate reservoir. It is located at

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an average depth of 8,100 ft subsea and has a mean net oil column of about 200 ft. Although the field was discovered in 1962 and was in commercial production from 1968, it was produced at a low rate (mostly production to reserves ratio < 0.5) due to limited production demands and processing capacity of the crude processing facilities (GCs). Accelerated production started about 5 years ago with the drilling of 70 producers, installing Electrical Submersible Pumps (ESP), implementing water shut-off jobs and commissioning of two super GCs.

The current production strategy is to produce it at a plateau of 250,000 bopd and extend the plateau through additional development activities like infill drilling, pressure support, etc. This required integration of a large volume of drilling and surveillance data and building an improved geological and reservoir model. Predicted performances of the different cases were evaluated mainly on the basis of oil/water production profile, pressure decline, plateau period, acceleration of production, ultimate recovery and migration across the concession line.

A team of geoscientists developed a complex geostatistical geologic model, considering 3-D seismic, log data from 170 wells, description of about 6,000 ft of cores from 31 wells, etc. The geological model has improved definitions of porosity, permeability, and Sw obtained by incorporating new petrophysical calculations, the properties assignment by rock types and representation of reservoir heterogeneity at the flow-unit scale through appropriate application of deterministic, stochastic, and object modeling. The fine-scale geologic model was built and upscaled using a hybrid procedure involving statistical methodologies. The upscaled models were sense-checked through streamline simulations.

The simulation model was history-matched with 45 years production and surveillance data, which included oil, gas, and water production from 165 wells, about 1,900 data points on static/buildup pressures of the wells distributed through the historical production period and Repeat Formation Test (RFT) pressure profile in 45 wells. Additional data considered were saturation variation detected from open-hole and thermal decay logs, well-productivity index (PI) data and flowing bottom-hole pressure. History matching of the well and field production performance is done by ensuring the quality of the engineering data and applying minimum modifications to the geologic model maintaining the integrity of the geologic descriptions. An excellent history match was obtained on a field-wide, regional, and individual well basis for water production, static pressure, and RFT profile. The reason for the success in achieving an excellent history match can be attributed to the care taken during data collection and analysis, improved geologic model, the upscaling procedure applied in converting the geologic model to the simulation model, and the processes applied in the history match.

Although there are only three crude processing facilities (GCs), facility network for the prediction cases has been prepared with some pseudo-flow stations to model preferential production from specified areas. The wells rates in the prediction mode were constrained by the target production from the specific GC. An uptime factor has been implemented at well level to account the impact of downtime due to work-over delays, Electrical Submersible Pump (ESP) run-life and ESP performance efficiency. Based on the different case studies, growth options and possibilities are identified in accordance with the asset's long-term production strategy, along with the required additional development activities and modification of surface facilities to achieve the optimum production and reserves.

IPTC 11688 Investigation of miscible gas flooding in north Kuwait reservoirs by experimental and modeling approaches

Moudi Al-Ajmi (KOC), Asma'a Al-Ghadban (KOC) and Ealian Al-Anzi (KOC)

The North Kuwait long-term strategy is designed to increase its oil production as per Kuwait Oil Company (KOC) development plans. North Kuwait's production to date is characterized by large, massive reservoirs undergoing natural depletion supported by strong natural aquifer drives and, in some reservoirs, natural aquifer support is supplemented by water flooding. In order to maintain production, the current primary and secondary (water flood) recovery mechanisms must be advanced into secondary and tertiary (EOR) in the main North Kuwait reservoirs. To date, there is zero EOR production from KOC reservoirs. Very limited lab work has been conducted with majority of it on North Kuwait reservoirs. These experiments include: (1) swelling tests, (2) slim-tube tests, (3) composite core immiscible tertiary gas flood. This study is the first to define a comprehensive EOR lab studies in a systematic manner to assess the EOR potential in North Kuwait.

The study focuses on the gas injection EOR option, as more than 90% of North Kuwait reservoirs are suitable candidates for this method. The injection gases considered are pure and impure CO_2, N^2, and hydrocarbon gases. This paper presents a review of the previous lab work, and recommends performing additional laboratory tests for each major reservoir in North Kuwait. Specific attention is focused on KOC's limited gas injection experiments. These tests have been a useful tool for EOR screening of

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North Kuwait reservoirs, as: (1) equation of state (EOS) has been developed and used for simulation these injection studies, (2) one-dimensional slim-tube compositional simulation models were built using the matched EOS to validate slim-tube test data. (3) Additionally, the available Minimum Miscibility Pressure (MMP) correlations were used for comparison. The paper also presents the approach to predict the MMP of North Kuwait reservoir fluids with various injection gases other than the gases used in the actual experiments.

IPTC 11324 Long-term field development opportunity assessment using horizontal wells in a thin, carbonate reservoir of the Greater Burgan Field, Kuwait

Anil K. Ambastha (Chevron), Dawood Al Matar (KOC) and Eddie Ma (KOC)

The Mauddud reservoir in the Greater Burgan field is a thin, carbonate reservoir containing light oil in a 10–20 ft thick target zone with "good" porosity. Matrix permeability is low and natural fracture density can be variable in this reservoir. Thus, this reservoir must be exploited using horizontal wells. In the early 1990s, 16 horizontal wells were drilled in this reservoir. Five more horizontal wells have been drilled in the last two years in an effort to scope-out the long-term potential of this reservoir. In conjunction with the drilling of recent horizontal wells, a comprehensive reservoir characterization program culminating into a full-field reservoir simulation model has been completed. The 24 million cell geological model was scaled up to a 9 million-cell model at a 50 x 50 m areal grid level to properly incorporate flow characteristics of horizontal wells in the simulation model. Matrix permeability of the scaled-up model was enhanced using a unique process based on analytical solutions for short fractures and fracture density/orientation mapping for the entire field.

This reservoir simulation model has been history-matched for the 13-year production history of 19 horizontal wells using only a global permeability multiplier and water relative permeability curve shape modification. This model has been used in the forecast mode to assess long-term field development opportunity for the Mauddud reservoir. Primary depletion results show that horizontal wells drilled in an intelligent manner in this difficult reservoir hold the key to an economic development of this reservoir. This paper highlights integrated geological, geophysical, rock mechanics, petrophysical, and reservoir simulation work required to assess the potential of a difficult reservoir characterized by low matrix permeability, thin pay, variable fracture density, and lack of aquifer support. This paper also presents a "stand-alone" full-field, history-matched, parallel simulation model of the Mauddud reservoir for the first time.

IPTC 11410 Jurassic fault framework and structural style in Bahra field and its impact on fracture development

Nikhil Banik (KOC), Sunil Kumar Singh (KOC), Aref Abdulsalam Abdullah Al-Dohiem (KOC) and Neema Hussain Al-Ajmi (KOC)

Jurassic discoveries in Kuwait during recent years have met with potential successes and are among the landmark achievements in its exploration history. In this list, the success in Bahrah area of northern Kuwait attracts special significance for its light oil production from fracture dependent permeability/porosity from an otherwise low-matrix porosity carbonate reservoir. The Jurassic Middle Marrat and Najmah formations are the main recognized reservoirs with proven hydrocarbon in Kuwait. The well evidence in and around the area suggests that Middle Marrat Formation in Bahrah area has a mud-prone facies in an outer mid-ramp to outer-ramp setting having low matrix porosity. Therefore, hydrocarbon potential and productivity of the reservoir dominantly depends upon open-fracture network connectivity.

To evaluate this reservoir characteristics and favorable hydrocarbon traps, the structural style of Bahrah and their fault framework were analyzed through detailed mapping of the area. The study brought out N-S elongated faults, which changed dominantly to a NW-SE direction towards the north. This change of fault orientation impacted a rotation effect over a considerable area, which is expected to develop intense fracture zone. The large Bahrah prospect is also a combination of several independent structural and fault closures associated with a compressional stress system that paved the way for good fracture development. Seismic attributes such as spectral decomposition, edge slices, and frequency-related trace attributes, coupled with fracture interpretation from core and image logs in the wells, have inferred these fracture corridors. The studies through geomechanical modeling and curvature maps further consolidated the possible recognition of fracture corridors in the area. Use of ant-tracking analysis to define the sub-seismic scale, finer faults and lineaments were identified to track fracture corridors and appropriately place the well locations with desired deviations to penetrate through a greater number of fractures.

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IPTC 11607 Evaluation of horizontal wells in a thick oil column of Greater Burgan field

Paban K. Chakraborty (KOC), Muktibrata Bhattacharya (KOC), Naz H. Gazi (Halliburton) and Raed H. Morad (KOC)

The Greater Burgan field located in southeastern part of Kuwait is producing around 90% from the Third Sand clastic reservoirs and is considered as aswing producer. This Lower Cretaceous Third Sand Middle has excellent lateral and vertical flow system without persistent flow barrier. Horizontal well plan was targeted on this sand in areas of significant oil columns in structurally favorable areas for optimum oil production without significant drop of reservoir pressure. Exploitation of oil from this high permeability sand over the years has resulted in coning, fingering, non-uniform fluid flow resulting in by-passed oil pockets. An integrated reservoir management plan consisting of both vertical infill wells for production from multi-layered sands, and horizontal wells for Middle Third Sand has been conceived to effectively sweep the oil. Thirteen horizontal wells have been drilled so far in oil columns varying from 80 to 150 ft. The perforation intervals in the horizontal section vary from 1,100 to 2,330 ft in order to achieve maximum reservoir contact area for sustained significant dry production.

The horizontal wells have provided significant insight into the lateral heterogeneity of this sand affecting oil contribution. The completion of these wells involved perforating vertically upwards in the direction of highest stress to minimize sand production and to complete mostly as under-balance for improved well bore cleanup. Production logging was carried out in eight wells. This paper highlights the challenges in designing and completing successful horizontal wells in the Third Sand Middle formation of the Burgan field. Also discussed is the critical understanding of oil entry mechanism from the flow profile under very low drawdown pressure. The close monitoring of multiphase fluids flow patterns, both in offset wells and within the well bore, is also described.

IPTC 11395 Pattern balancing and water-flood optimization of the supergiant Sabiriyah field, North Kuwait: A case study

Robert A. Clark, Jr. (BP), James Lantz (BP), Hossein Karami (Schlumberger) and Moudi Al-Ajmi (KOC)

This paper outlines the successful integration of subsurface, water-handling, well surveillance and production operations teams across the northern Kuwait asset to significantly improve the operating procedure for water flooding the Mauddud reservoir in the Sabiriyah field. This effort required a new way of managing this reservoir; a multifaceted approach of balancing voidage with injection, conducting extensive surveillance/analysis within the reservoir to assess the efficacy of various courses of action and, most significantly, adjusting various teams' "key performance indicators" (KPIs) to align injection and production allowables with sound reservoir management principles. An innovative, unified information management system was used to monitor voidage replacement ratio (VRR) to provide a basis for pattern balancing. Extensive surveillance operations provided the data necessary to monitor individual pattern balance, water cut performance, optimize areal sweep efficiency by adjusting injection and production allowables, assist in planning water shutoff operations, and design new completions.

Water flooding the Cretaceous Mauddud reservoir is in an early stage of operations. Water injection commenced in 12 of 17 pre-drilled water-flood patterns in 2000. These wells were drilled on an inverted nine-spot pattern with spacing of 250 acres per well to quickly provide coverage over the major portion of the reservoir. Surveillance data indicated the reservoir is relatively well connected. Pattern VRR, pressures, and water cuts were somewhat out-of-balance prior to engaging in this effort. Now, individual water-flood pattern balance is significantly improved and the field-wide VRR is approximately 1. Sound reservoir surveillance and water-flood management procedures implemented within a diverse group of teams that have performance goals aligned with "best practice" has resulted in effectively re-balancing this major water flood. This effective integration of teams retains the flexibility to adjust for an ongoing development of this super giant field.

IPTC 11518 Formation testing strategy based on quick-look data evaluation from a fractured basement reservoir: A case study from Kharir field, Yemen

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In Kharir field (Yemen, Block 10), a major hydrocarbon accumulation is hosted in fractured basement. Along drilled basement sections, only restricted intervals account for flow. Accurate identification

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of open flowing fractures (amid numerous planar features) is crucial to characterize and monitor non-conventional basement reservoir. At well Kharir-XX, relevant logs were acquired in single run (Resistive-Acoustic Borehole Image, Fullwave Cross-dipole Acoustic, Induction and Spectral gamma ray). The logging program was designed to provide maximal time for flowing intervals identification before decision to perform Formation Tester Run.

Acoustic image and Cross-dipole full-wave data acquired RIH were sent from wellsite, QC'd and processed. Interpretation focused on Acoustic Travel Time Image, which is a key parameter for flowing fracture recognition. Wellsite Monopole VDL images were used for evaluation of Stoneley Wave Reflectors. High-definition Array Induction Log and Micro-resistivity Borehole Imager data were logged whilst POOH and sent at regular intervals for evaluation. From the above logs, fractures that appeared large, continuous and visible on the Acoustic Travel Time (potentially open at borehole wall); with a conductive appearance on micro-resistivity images were located and oriented. These fractures were then ranked taking into account their good match with while-drilling gas shows and increased rate of penetration. From tens of candidate intervals only twelve were selected for testing. Interval Formation Tester was deployed using Dual Inflatable Packer System (1 m packer spacing). Borehole images were used to accurately position packers to avoid risking damage or no/lost seal. Formation Tester was run under Aphron mud system (reversible cake). Special clean fluid carriers inflated packers, thus avoiding risk of plugging fluid lines inside the tool with congealing mud. At well Kharir-XX, 80% of selected sampling stations gave reliable formation pressures, pressure transients, fluid gradients, mobilities and representative formation fluid samples.

IPTC 11361 The surveillance and optimization of a water-flooded fractured-carbonate reservoir

L.M. Dittaro (Imperial Oil), T.L. Holding (Imperial Oil) and C.M. Schwindt (Imperial Oil)

The surveillance and optimization of Norman Wells, a waterflooded fractured-carbonate reservoir in northern Canada, is presented. Discovered and on-production since 1920, Norman Wells is one of Canada's largest conventionally produced oil fields. Full development of this resource was undertaken in the early 1980's when directional and horizontal drilling technology allowed access to the majority of the reservoir, which underlies the Mackenzie River. Several artificial islands were constructed to provide pads for directional injection and production wells. The five-spot waterflood patterns were aligned and elongated to take advantage of the directional permeability associated with the natural fracture system. To optimize production and increase ultimate recovery, a sophisticated multi-disciplinary approach to reservoir and production surveillance has been employed. Basic surveillance methods including frequent well testing, fluid sampling, and gas sampling to ensure the accurate allocation of volumes. Surface pressure measurements have been used to accurately allocate production/injection volumes and monitor the status of the wells. Pressure measurements, including static, build-up, fall-off, flowing, and interference well tests have been utilized to monitor reservoir pressures, inflow/outflow performance and reservoir connectivity. Waterflood conformance has been assessed through the use of tracers, cased-hole production logging and injection logging. Waterflood effectiveness has been optimized through the use of voidage replacement analyses, Hall plots, the imposition of injection targets, and staging of fresh and produced water volumes. A holistic assessment of the surveillance information gathered has been accomplished through the use of streamline and floodfront analyses, material balance models, and several generations of full-field reservoir simulations. Ongoing optimization of the depletion of this complex reservoir has resulted in a 20% increase in the expected ultimate recovery since full-field start-up. An example of how the surveillance information has been utilized to improve reservoir performance is presented.

IPTC 11578 New oil entrapment in Lower Minagish Member, Minagish field, Kuwait

Taher El Gezeery (KOC), Khaled Al-Mutairi (KOC), Adel Ebaid (KOC) and Mohamed Mostafa (KOC)

The Minagish field has several reservoirs with oil accumulated primarily in lower Cretaceous Minagish Oolite -middle member rocks. This giant carbonate hydrocarbon accumulation in the Minagish field was discovered in 1958 and accounts for more than 80% of oil production in the field. The Lower Minagish end member consists largely of clean to slightly argillaceous and/or carbonaceous fine-grained peloidal packstones that were deposited in a low-energy platform setting equivalent to a very gently sloping outer-ramp. Two significant flooding events divide the Lower Minagish Formation into three main productive zones: upper, middle and lower. The contact between the lower and middle members is an irregular one with a gradual diagenetic transition from limestone to tight dolostone. The Lower member has a gross

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pay of about 220 ft above recorded lowest known oil at about 10,000 ft tvdss close to the top of the Makhul carbonates (which forms the bottom seal of the reservoir). The recent conventional cores and image log data from the crest of the structure show that the Lower Minagish has faults and fractures, which could provide permeability assist. There are 130 wells that have been drilled in this field targeting the Minagish Oolite (middle member); however 10 wells have recently been deepened to evaluate the oil potential of the Lower Minagish and the underlying Makhul formations. Five wells tested in the upper and middle zones have produced rates in the range of 400 to 4,300 barrels of oil per day with the oil from the upper and middle zones having an API of 31° to 20.5°. This is significantly lower than the Minagish Oolite oil with an API range of 28° to 32°. This probably indicates a later reservoir filling than the Minagish Oolite oil emplacement. The discovery of this new oil is expected to enhance the oil-in-place of the field. Although only wells in the northern block have been drilled and tested so far, the 3-D seismic mapping suggests possible deeper oil down to in the southern block.

IPTC 11369 Al Khalij: The quest for oil in a highly complex carbonate field

David Foulon (Total), Florence Viéban (Total), Rashed Noman (QP), Bernard Faissat (Total) and Ismail A. Al-Emadi (QP)

Al Khalij could be viewed as the archetypal complex carbonate field. Laterally sealed by a stratigraphic closure, the reservoir monocline consists in a *layer cake* of alternating good and poor quality rock whose fabric has been intensively reworked during multiple phases of diagenesis. Additionally, the oil column is relatively thin and average water saturation above free water level exceeds 85%. Al Khalij development challenge can thus be formulated as: "How to efficiently recover a large oil accumulation trapped with much larger amounts of water in the capillary transition zone of a highly heterogeneous reservoir of uncertain boundaries overlying an active aquifer?" To meet a challenge of such magnitude, a phased development was undertaken and completed recently, nine years after kick-off. Even so, the expected recovery factor remained low and the reservoir model unmatched. This paper describes the extensive work program implemented to better understand early-time reservoir behavior and find ways to increase recovery.

Starting with a "back to the rocks" approach, a wide range of studies and additional measurements were undertaken, culminating in full-field reservoir simulations. Innovative modeling and interpretation techniques were implemented to extract maximum information from formation pressure and pressure build-up measurements. Where key uncertainties remained, specific solutions were sought in terms of enhanced data acquisition and monitoring programs, from petrophysical measurements on full size cores to injection PLTs in oil producers. Integrated static and dynamic syntheses reviewed all resulting information to better assess critical reservoir heterogeneity levels. A specifically designed dual-porosity simulation model was built to properly represent the small-scale heterogeneity impact, and successfully history matched. In less than two years, a full-field redevelopment plan was defined that is expected to double the recovery factor. The innovative acquisition, interpretation and modeling techniques developed in the process could fruitfully be applied to other complex fields.

IPTC 11467 Derivation of relative permeability and fractional flow behaviour from the inversion of saturation logs in horizontal wells with application to water shut-off and predicting volumetric sweep efficiency

Jeremy Harris (PDO)

An inversion method is presented that uses saturation log profiles recorded in horizontal wells to derive relative permeability and fractional flow properties for a water-flooded carbonate reservoir. Observed water-saturation profiles decreasing horizontally away from hydraulically conductive faults suggest a line-drive type encroachment of water into the fault-bound matrix blocks. The waterfronts have produced saturation profiles analogous to that predicted by Buckley-Leverett displacement theory, including the characteristic shock front. These profiles record parameters such as irreducible water saturation, the shock-front saturation, average saturation behind the front, and the residual oil saturation. These parameters are used to define boundary conditions on a fractional-flow plot using Welges method. A fractional-flow curve, which meets the boundary conditions, is then derived by changing the shape of the controlling relative permeability curves. The observed saturation profiles also show a correlation with porosity, allowing a suite of scanning curves to be derived for each porosity class. The reliability of the method is demonstrated by plotting the average pulsed-neutron-capture log saturations at the perforations against the producing watercut at the time of logging on the fractional-flow graph.

The fractional-flow curves are used to discriminate between wells that produce at the correct water cut

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from wells that could benefit from water shut-off. The curves are also utilised for forecasting water-flood performance. Identification of additional perforation and water shut-off activities amounted to significant oil gains over the past three years from very mature well stock. They provided new insight into the oil displacement process inferring higher mobility to water than previously suggested from core-plug data. Improved modelling of well and reservoir performance. The presentation is the first time that non-synthetic, saturation-front profiles are presented in the literature and used to derive dynamic properties.

IPTC 11411 Key learnings from history matching a thermally assisted gas oil gravity drainage pilot in fractured reservoirs

A. Ikwumonu (PDO), K. Rawnsley (PDO), M. Habsi (PDO) and R. Penney (PDO)

Globally large volumes of heavy oil are currently locked in shallow low-permeability reservoirs. If they contain sufficient natural fractures then one of the most viable recovery processes is thermally assisted gas oil gravity drainage. In this process steam is injected into the fracture system from where it heats the oil in the matrix, which reduces the oil viscosity and accelerates gravity drainage. The economic viability of this process is largely determined by the spacing of the fractures. Large blocks take longer to heat than small blocks, and the correct description and thermal simulation of these across the reservoir is critical to decision-making. Arriving at the appropriate reservoir description of the fractures for full-field simulation modelling requires input of the geological matrix and fracture model scenarios, a spacing-averaging method per grid block and the geometric shape factor term per grid block. Each of these contains its own uncertainties. The objective of this paper is to access each parameter and their impact on recovery.

For a given heterogeneous geological description, determination of the appropriate average spacing per simulation grid block is a non-standard operation. A number of techniques have been assessed including arithmetic and square-weighted averages. In addition a number of thermal shape factors used in dual permeability/porosity simulators are tested against single-porosity results. Impact on recovery and produced fluid temperatures of the above parameters was investigated through multiple reservoir simulation models. A history-matching approach was proposed and used in matching a pilot steam-injection scheme. This included matching the measured temperatures, oil-rim position, and production data gathered during a pilot. Conclusions are made regarding the importance and relative impact of the fracture characterisation, fracture-spacing averaging and shape factors on recovery.

IPTC 11713 Water shut-off techniques to combat premature water breakthrough in Mauddud carbonate reservoir: An efficacy analysis

Ajith Kumar (KOC), Moudi Fahad Al-Ajmi (KOC), Ealian Al-Anzi (KOC), Robert A. Clark, Jr. (BP), Mohamad Khater (Kuwait Santa-Fe) and James Lantz (BP)

The Mauddud is a major hydrocarbon bearing formation in Sabiriyah field of northern Kuwait. This carbonate reservoir is under depletion drive with no aquifer support and is currently producing under water flood with average water cut of 26%. Water injection started in 2000 under a 9-spot water-flood pattern system and the water flood is maintaining a good pressure support in the reservoir close to initial reservoir pressure and well above bubble-point pressure. However, the water production increased significantly due to premature water breakthrough, particularly in edge wells. This has led to an immediate need for implementing effective water shut-off techniques for decreasing water production at the subsurface level to balance and better control the sweep of the reservoir. Consequently eight edge wells were identified after detailed studies of production history, PLT, water-cut trend etc and taken-up for water shut-off jobs during the 2005 and 2006. Although in many of these wells there were clear indications of water breakthrough from bottom perforations, the option of plug-back cementation could not be attempted for completion constraint as the Mauddud was completed in short string of all the eight dual wells selected.

The methodology adopted was cement squeeze followed by selective perforation keeping away from the possible high permeability "thief" zones based on the PLT analysis mainly. Every effort was made to ensure the integrity of the cement squeeze by conducting a positive pressure test followed by negative test during workover job. Utmost emphasis was given for a successful negative test at 500 psi, which is the representative operating draw-down for Mauddud producers. Consequently squeeze jobs had to be repeated several times with special types of cements in certain cases, in pursuit of successful positive and negative tests and thereby accomplishing an effective squeeze job. The water shut-off jobs on these wells had mixed success and an in-depth analysis of pre-post job scenario on these wells is presented in this paper.

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IPTC 11630 Using down-hole control valves to sustain oil production from the first maximum reservoir contact, multilateral and smart well in Ghawar field: A case study

S.M. Mubarak (Saudi Aramco), T.R. Pham (Saudi Aramco), S.S. Shamrani (Saudi Aramco) and M. Shafiq (Schlumberger)

This paper describes a case study detailing planning, completion, testing, and production of the first Maximum Reservoir Contact (MRC), Multilateral (ML) and Smart Completion (SC) deployment in Ghawar field. The well was drilled and completed as a proof-of-concept. It was completed as a trilateral and was equipped with a SC that encompasses surface remotely controlled hydraulic tubing retrievable advanced system coupled with pressure and temperature monitoring system. The SC provides isolation and down-hole control of commingled production from the laterals. Using the variable positions flow-control valve, the well was managed to improve and sustain oil production by eliminating water production. Monitoring the rate and the flowing pressure in real time allowed producing the well optimally. The appraisal and acceptance loop of the completion has been closed by having this well completed, put on production and tested. Approval of the concept was achieved when the anticipated benefits were realized by monitoring the actual performance of the well. Leveraged knowledge from this pilot has provided an insight into SC capabilities and implementation. Moreover, it has set the stage for other developments within Saudi Aramco.

SPE 100270 A practical approach in building upscaled simulation model for a large Middle East carbonate reservoir having long production history

C.V.G. Nair (KOC) and E. Al-Maraghi (KOC)

A comprehensive reservoir model that provides excellent turnaround time for history match and evaluation of different development scenarios had been developed through careful application of upscaling methods for the large carbonate reservoir of Umm Gudair field located in Kuwait and Partitioned Neutral Zone. The model was built maintaining integrity of the geological model. The detailed geologic model, built using the latest techniques, was very large (157 layers, 10 million cells) and it was necessary to upscale the model into a reasonably sized simulation model that runs smoothly with a good turnaround time to make multiple runs to match 42 years oil/water production and pressure history of about 200 wells. The vertical upscaling was to be done maintaining the integrity of the fine-scale geological model, preserving physics of the displacement process and providing provisions for water shut-off jobs implemented through squeezing-off bottom perforations.

Although the flux-based upscaling techniques provided guidance, it alone was insufficient to optimize the layering scheme for the simulation model. A hybrid approach combining the elements of the methods of minimizing variation and flux, manual judgment and streamline simulation was applied to generate a vertically upscaled model with 42 layers that effectively replicated the fine-scale fluid flow behavior. Two simulation models were generated with different areal dimensions: a coarse model with 200 x 200 m (to accelerate the history match process) and a fine-scale model with 100 x 100 m (983,000 active cells) for infill drilling studies. Excellent history match has been achieved and the model has been demonstrated as an effective reservoir management tool for further field development. This paper discusses the steps applied towards effectively converting the geologic model to simulation model through upscaling, the systematic approach towards building the history-match model highlighting the critical steps and an overview of the quality of history match.

IPTC 11420 The evaluation of gas reservoir for production allocation using fingerprint: A case study

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The Z gas field of PDO is currently contributing of Oman's gas requirements for LNG export. The field is producing from the rich gas-condensate bearing Reservoir A and lean gas-bearing Reservoir B and Reservoir C sandstone. The total number of wells until to date is 22 development wells drilled in the field, of which 11 wells are on production, 6 wells produce from Reservoir A only, 1 well from Reservoir B only, 3 are commingled Reservoir A, B and C, and 1 well from Reservoir A and C. The average formation split from the field predicted 45% Reservoir A, 20% Reservoir C and 35% Reservoir B, and specifically it varies from well-to-well and depends on the draw-down. The primary surveillance tool is used to allocate a relative production for two reservoirs by utilizing a MPLT surveys. Recently, a campaign of multi-phase flow meters coupled with PLT's was initiated. Gases in the B and C reservoirs have very different carbon-isotope character than those in Reservoir A. These differences are unique

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and can be used to calculate mixing proportions of commingled production. The proposed solution to this problem was the derivation of three models that accounts for variable isotopic and compositional characteristics, and trends in which all such data could be correlated. A lesson-learnt and limitation is captured from this fingerprint study.

IPTC 11438 IOR/EOR in South Oman heavy oil fields

Salim Sikaiti (PDO), Jeroen M.M. Regtien (PDO), Ahmed A.S. Azkawi (PDO), Said Al-Harthi (PDO) and Elaine Sandison Leith (PDO)

Several heavy oil fields in Oman are undergoing a rejuvenation using a variety of Improved and Enhanced Oil Recovery methods. The sandstone reservoirs, generally at a depth around 1,000 m, contain heavy oils with API gravities of 18^o to 22^o, viscosities between 90 and 400 cp and exhibit variable reservoir properties of around 20% porosity and 500–2,000 mD permeability. Mobility ratios are adverse and all fields demonstrate early water breakthrough and high BSW under primary development. Fields with strong bottom waterdrive are redeveloped with a focus on cost-effective infill drilling and water shut-off techniques. Good results have been achieved through segmentation of horizontal well bores with swellable elastomers allowing for targeted mechanical or chemical water shut-off. Innovative infill drilling technologies such as jet drilling and ultra-short radius are either ongoing or in preparation. Further increases in ultimate recovery through *in situ* combustion and high-pressure steam injection are being pursued.

The fields with weak or no aquifer support are being redeveloped through water-floods and chemical or thermal floods. Execution of a polymer project is ongoing with first polymer injection expected in 2008, following a very favourable water flood response despite geological complexities and adverse mobility ratios. Studies are ongoing into expansion to other areas and a follow-up alkaline surfactant polymer flood. The redevelopment rationalized the existing infrastructure and provides support for water floods in satellite fields as well. Redevelopment of a second group of fields is being pursued through thermal methods. Steam injection tests are in final stages of preparation and will start in 2007, followed by phased full field developments. Given the specific reservoir and fluid conditions there are not always analogs and several of the developments pose unique challenges. The paper will present a status overview of several water flood, polymer and thermal projects as well as key challenges and solutions.

IPTC 11375 Reservoir connectivity: Definitions, examples, and strategies

John W. Snedden (ExxonMobil), Peter J. Vrolijk (ExxonMobil), Larry T. Sumpter (ExxonMobil), Mike L. Sweet (ExxonMobil), Kevin R. Barnes (ExxonMobil), Elijah White (ExxonMobil) and Mike E. Farrell (ExxonMobil)

Reservoir connectivity, and its inverse, compartmentalization, is a critical area of petroleum industry research and business application. However, significant differences in how it is defined, measured, and modeled exist among companies. For some, connectivity is defined relative to an entity such as a well or set of perforations in a reservoir. Others prefer reservoir connectivity indexes, using a set of often subjectively defined criteria to gauge how problematic a field will be to develop or exploit. We have developed a technology called "Reservoir Connectivity Analysis" (RCA) to investigate field compartments and associated connections. A compartment is precisely defined as a trap, which has no internal boundaries that would allow fluids to reach equilibrium at more than one elevation. Compartment boundaries include sealing faults, channel margins, shale-draped clinoforms, paleokarst fractures and other diagenetic boundaries. These can separate hydrocarbons and aquifers within a field or discovery. Connections between compartments include fault juxtaposition windows, erosional scours between channels, and capillary leakage. Compartment boundaries include spill and breakover points, defined on topseal and baseseal maps.

We also find that it is important to separately define and investigate "static" and "dynamic" connectivity. Static connectivity describes the native state of a field, prior to production start-up. Evaluation of static connectivity is the basis for proper assessment of original hydrocarbons in place and prediction of fluid contacts in unpenetrated compartments. Dynamic connectivity describes movement of fluids once production has begun. Initiation of production actually perturbs the original fluid distributions as pressure and saturation changes proceed in a non-systematic fashion. An example of RCA application in the Gulf of Mexico is provided to illustrate how RCA can generate testable fluid connectivity scenarios and explain troubling production anomalies.

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IPTC 11376 Field monitoring: Applications of Total Corporate Integration Strategy

Aurélien Treguier (Total), Jacques Danquigny (Total) and Alain Louis (Total)

Important progress of digital technologies over the past few years radically changes the way Total corporate acquires, processes and spreads the data coming from its upstream assets. The rising generation of oilfields already reaps the benefits from the use of these technologies through a patchwork of customized applications ranging from measurement up to visualization. This combination of both existing and leading-edge technologies ensures to constantly reach the field optimal efficiency. This result is achieved by a close follow-up of the field behaviour from reservoir to point of sale. This paper presents examples of early successful achievements, fit for the purpose of local assets, dealing with the monitoring of reservoirs (4-D, tracers, etc.), wells, pipeline flow assurance, rotating equipments. It emphasizes recent applications of the Total corporate integration strategy, dedicated to improve overall field performance. This activity is implemented in a single program named Field Monitoring and focused on the following topics: reservoirs, wells, networks, plants, and IT architecture.

Total has gathered all the above-mentioned tools and technologies within its E&P Field Monitoring program, so as to accelerate the implementation of technological breakthroughs by: (1) capitalizing on existing asset-specific tools, dedicated to real-time monitoring and optimization; (2) ensuring quick deployment of new developments across assets and disciplines; (3) promoting collaborative work and data sharing; (4) addressing complex operation issues (e.g. deep offshore); and (5) introducing systems to spawn conservation efforts and reduce GHG emission intensity through a close surveillance of their origin

Within a unique, simple and long-lasting IT architecture, the Field Monitoring tools are web-based and remotely accessible. Data validation, advanced calculation and simulation are associated to generate useful pieces of information such as KPI's, alarms and diagnosis wizards. This paper provides the details of one implementation of this strengthened concept demonstrating and turning into reality the corporate strategy. This feedback mainly focuses on software aspects rather than on hardware issues and business processes, presenting comprehensive information about the Field Monitoring integration strategy: how does Total structure and implement its program.

IPTC 11716 Complex and unconventional wells addressing difficult reservoir development: A case study of West Kuwait Jurassic reservoirs

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The Najmah-Sargelu unconventional fractured carbonate and Middle Marrat tight carbonate Jurassic reservoirs are spread across many fields in West Kuwait where new Jurassic oilfields are still being discovered. Oil is being produced since late 1980s mainly from Minagesh, Umm Gudair, Abduliya and Dharif structures. Drilling through over-pressured and fractured Najmah-Sargelu reservoir, lying below thick high pressure Gotnia Evaporites is challenging due to well control issues such as total mud losses and kicks compounded with high H_2S-high CO_2 corrosive environment. Moreover, pressure reversal in Middle Marrat reservoir and depleted pressures pose further complications resulting in costly wells. A total of 53 wells drilled in these fields until 2002, were all vertical except one Najmah-Sargelu high-angle well drilled in year 2000, which could not be tested due to complications during completion. Although many wells produced at high rates of 5,000–10,000 bopd, some failed to produce because they did not intersect productive fractures in Najmah-Sargelu or due to the low productivity index in tight Middle Marrat carbonates.

This paper presents an overview of recent efforts in planning and drilling unconventional wells addressing cost-effective development of multiple Jurassic reservoirs. The first such well, drilled in 2003, was a long-reach horizontal well that was successfully tested and produced from Najmah-Sargelu carbonates. This was followed by Kuwait's first long reach medium radius re-entry horizontal well in 2004 that was tested and completed open-hole in Middle Marrat reservoir successfully. A 1,100 ft lateral drain-hole for productivity enhancement in Marrat reservoir was successfully geosteered on planned trajectory in 2006 through re-entry. The well showed oil indication during initial testing; however, it was suspended due to post-stimulation complications during testing. Recently, the first deviated development well was drilled and completed where the trajectory was optimized for both reservoirs. The well successfully intersected, as planned, a fracture swarm in the Najmah-Sargelu where core was acquired and oriented to characterize the fracture zone. Other complex wells

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included vertical deepening for transferring water producing Najmah-Sargelu well to Middle Marrat extending productive life of non-usable well. Well planning for a complex Najmah-Sargelu deviated - Middle Marrat horizontal well was completed early this year and drilling is expected to be finished in 2007 followed by a long reach Najmah-Sargelu re-entry horizontal sidetrack, besides the first Middle Marrat reservoir water injector in 2008. These unconventional complex wells have successfully met technical challenges in planning and drilling while addressing productivity enhancement and cost-effective development of multiple Jurassic reservoirs. Learnings gained in these wells will go a long way in finalizing cost-effective field development plans incorporating optimal well trajectory, completion designs and off-take strategies for maximizing recoveries from these difficult and challenging reservoirs.

IPTC 11512 The application of unstructured gridding techniques for full field simulation of a giant carbonate reservoir developed with long horizontal wells

H. Vestergaard (Maersk), H. Olsen (Maersk), A.S. Sikandar (Maersk), I.A. Al-Emadi (QP) and R. Noman (QP)

This paper presents a case history on reservoir simulation modelling of a giant, complex, low permeability, carbonate reservoir, which has been completed with many long horizontal wells. The lateral magnitude of the Al Shaheen field in Qatar and the multiple radial layout of the 75 very long horizontal wells in the field posed a challenge in modelling of individual well performance using a manageable grid size with an acceptable run time for history matching. The gridding dilemma was solved by use of 2.5-D PEBI grids around each individual well bore. This allowed for sufficient resolution between wells and also aligned the grid with the well paths thereby avoiding grid non-orthogonality issues. The initial fluid distribution and wettability dependent flow properties added further complexity to the reservoir simulation model. This paper describes how tilting free-water levels, separate gas caps and large lateral variations of oil properties across the field were captured in the initialisation of the simulation model. Dynamic flow properties in the reservoir are heavily dependent on wettability and oil properties and the paper describes the rigorous implementation of a complex petrophysical model in the reservoir simulation model by use of end-point scaling.

IPTC 11326 The In Salah Gas CO_2 Storage Project

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In Salah Gas is a joint venture of BP, Sonatrach and Statoil, which started in July 2004, producing 900 bcf/d gas for sale in Europe. The natural gas contains up to 10% CO_2, which has to be reduced to 0.3% before the gas is sold. Hence, 1 million tonnes/year CO_2 is produced. Rather than vent that CO_2 to the atmosphere (business as usual), this project re-injects it into the Krechba Carboniferous Sandstone reservoir via three horizontal wells at a depth of 1,900 m. CO_2 injection started in August 2004 and over the life of the project, 17million tonnes CO_2 will be geologically stored at a cost of $100 mm ($6/tonne CO_2 avoided). This project is an industrial-scale demonstration of CO_2 geological storage and is the first industrial-scale project in the world to store CO_2 in the water leg of a gas reservoir.

The In Salah CO_2 Storage Project is a five-year, $30 mm, Joint Industry Project (JIP) with participation from the EU and USA governments. The storage location is heavily instrumented and data is collected and analysed, to monitor the behaviour of the CO_2. Objectives are to: (1) demonstrate to stakeholders that industrial-scale geological storage of CO_2 is a viable GHG mitigation option. (2) Provide assurance that secure geological storage of CO_2 can be cost-effectively verified and that long-term assurance can be provided by short-term monitoring. (3) Set precedents for the regulation and verification of the geological storage of CO_2. A key part of the monitoring programme will be the deployment of a novel permanent seismic array, allowing frequent, real-time imaging of CO_2 migration through the storage formation. This will provide a benchmark against which alternative technologies can be evaluated. This paper will share results to date of the ongoing CO_2 monitoring project.

The following company abbreviations are used:

ADCO	:	Abu Dhabi Company for Onshore Oil Operations
ADMA-OPCO	:	Abu Dhabi Marine Operating Company, Abu Dhabi, United Arab Emirates
BAPCO	:	Bahrain Petroleum Company
BP	:	British Petroleum
CGGVeritas	:	Compagnie Générale de Géophysique - Veritas
IFP	:	Institute Français du Pétrole
KOC	:	Kuwait Oil Company
PDO	:	Petroleum Development Oman
PGS	:	Petroleum Geo-Services ASA
QP	:	Qatar Petroleum

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