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Selected geoscience and upstream abstracts from IPTC 2005, Doha, Qatar

The following selection of abstracts is reprinted from the Proceedings of the International Petroleum Technology Conference IPTC 2005, held in Doha, Qatar, on November 21–23, 2005. 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 relevance to the Middle East petroleum geosciences and related upstream disciplines, and grouped into the subjects listed to the right.

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 articles. The full contents of the papers (where available in the CD-ROM) are not reproduced here as the IPTC organizers note: "Permission to reproduce in print is restricted to an abstract of not more than 300 words; illustrations may not be copied. The abstract must contain conspicuous acknowledgement of where and by whom the paper was presented".

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MIDDLE EAST BASIN MODELING AND PETROLEUM SYSTEMS

"On-the-fly" stratigraphic basin modeling from seismic interpretation workstations (IPTC 10580)
Albouy, E., M.-C. Cacas and G. Dobranszky (Institute Français du Pétrole), and J.-M. Laigle (Beicip-Franlab)

Seismic interpreters already use the principles of sequence stratigraphy to help interpret the geometry and sedimentary facies of the sedimentary bodies seen on seismic data. Linking seismic interpretation to a well database containing information on bathymetry and lithology, by using ultra-rapid algorithms simulating sediment transport, can help the interpreter to rapidly test and modify the stratigraphic scenario inherently present in the geometry and nature of the surfaces that have been picked. This "on-the-fly" stratigraphic modeling should make seismic stratigraphic interpretation easier and simpler to perform. Various image-processing techniques can also be of help to the interpreter, both in determining depositional environment from seismic textural analysis, and in a more rapid identification of the key toplap, onlap, downlap and truncation surfaces present in the seismic data. Again, linking the textural information with the well database can lead to a better use of both types of data.

The above techniques have been applied to seismic and well data of the National Petroleum Reserve Alaska, as a structured workflow involving the construction of a detailed geomodel and time-to-depth conversion cube. For each of the sequences picked on the seismic, the direction and composition of the principal sources of clastic supply are determined, and paleobathymetrical maps are generated, all of which are coherent with the well data (interpreted lithology and depositional environment) and the picked thickness of the sequence on seismic. The interpreter can then choose to view the seismic data of the next sequence in "true stratigraphic position" by shearing to fit the modeled bathymetrical profile of the underlying sequence. He or she may also choose to review and reinterpret the well data or repick the seismic surfaces in the light of the realistic paleogeographical scenario generated by the stratigraphic modeling.

Source rock maturation modeling as an exploration and evaluation tool: an example fro the southern part of the Zagros Foldbelt in Iraq (IPTC 11017)
Al-Kubaisi, M.Sh. (University of Baghdad) and N.Z. Marouf (Al-Zab Petroleum Consulting Bureau)

Geochemical analyses of several hundreds of samples taken from a few tens of deep wells and surface sections in the Zagros simply-folded belt in northeast Iraq, show that there are two main source rocks in the studied area. The Middle-Upper Jurassic source rocks with an average TOC of 1.5% consist of Kerogene type IIS, and the Upper Triassic ones with TOC of 0.5% consist of Kerogene type III. The maturation of the Middle-Upper Jurassic source rocks was modeled using their measured physical parameters and based on the analysis of the Phanerozoic tectonic history of the northeastern margin of the Arabian Plate (Zagros Foredeep in northern Iraq). The burial and thermal histories of the sampled locations, and many hypothetical locations that are randomly distributed along the studied area, were also reconstructed. The results of the modeled maturation levels of these source rocks show a good correlation (correlation coefficient 0.90) with the measured maturation levels of the same source rocks at the sampling locations. These positive relationships imply that the modeling procedure and the modeling parameters were correct, and the results of the models are applicable to the whole basin.

A detailed structural study was also carried out, and several structure and paleogeographic maps and cross-sections were also constructed. The possible hydrocarbon migration routes were defined and correlated with the discovered present traps. The predominance of natural gas reservoirs in the southern parts of the Zagros Foredeep in Iraq versus the predominance of oil reservoirs in the northern parts, is also in very good correlation with the results of both the burial and thermal histories model and the reconstruction of the structural evolution of the studied area. The results of the correlations between the predicted locations of hydrocarbon trapping and the locations of the discovered actual traps were also very good. But the calculated amounts of the possibly produced hydrocarbons, since the time of the evolution of the present structures of the studied area, are more than three times greater than the actual presently discovered volumes of the hydrocarbons.

Sequence stratigraphy and distribution of Silurian organic-rich "hot shales" of Arabia and North Africa (IPTC 10388)

Grabowski Jr., G.J. (ExxonMobil)

The sequence stratigraphy of "hot shales" of the Silurian succession, determined from well-log correlation, is the basis for mapping the distribution and thickness of these organic-rich intervals. The sequences have been tied to a sea-level curve using published age control. The Silurian succession is a thick wedge of marine shale, with nearshore sandstones mainly in the upper part. Several intervals of organic-rich "hot shales" occur within the Silurian succession. A widespread basal "hot shale", up to 30 m thick, lies directly above, and thins by onlap, onto an erosional surface. The overlying unit of organic-lean shale and siltstone thins as it progrades in a basinward direction, forming a subtle clinoform geometry. Above this lies a basinally restricted interval of shale, which laps onto the underlying progradational shales. This pattern is repeated many times. The basinally restricted shales may be organic-rich, especially in the lower part of the Silurian.

The basal "hot shale" and basinally restricted shales are interpreted as lowstand-transgressive units above sequence boundaries. The basinward-thinning progradational shale-siltstone units are interpreted as highstand deposits. As the highstand units thin, the basinally restricted shales come closer together and distally merge to form thicker units of shale. These merged "hot shales" are interbedded with limestones that formed due to the reduction in detrital sedimentation in a distal setting.

Proximal basins (southern Ghadames Basin, Murzuq, Widyan and Rub' Al Khali basins) contain only the basal "hot shale", which is absent on paleohighs within and around the margins of the basin. Basins updip of the proximal basins (Kufra, Western Desert) lack the basal "hot shale" or any other "hot shales". More distal areas (northern Ghadames Basin, northeastern Arabian Platform and Zagros Foldbelt) contain multiple "hot shales", improving the chance for migration of petroleum to sandstone reservoirs in the upper part of the Silurian or overlying Devonian.

Integrated geochemical and basin modeling analysis of the Jurassic and Cretaceous Hanifa hydrocarbon system in Qatar (IPTC 11025)

Guthrie, J. and W. Maze (ExxonMobil); I.A.A. El-Amadi and M.E. Zahran (Qatar Petroleum)

Organic-rich mudstones of the Tuwaiq Mountain and Hanifa formations of the Jurassic Hanifa Supersequence are the major source rocks for much of the oil in the Arabian Gulf. An integrated geochemistry and basin-modeling study on these source rocks and their oils was conducted to explain the distribution of petroleum accumulations within the Hanifa hydrocarbon systems of Qatar. Principal component analysis (PCA) of biomarker and stable carbon isotope data for oils and condensates delineates three major hydrocarbon systems in Qatar: (1) Jurassic Hanifa-sourced oils; (2) Cretaceous Shilaif-sourced oils; and (3) Silurian Qusaiba-sourced condensates. The biggest contribution to the PCA comes from Factor I where 63% of the variance in the data is primarily due to source rock facies variations. Oil-to-oil correlations indicate that the Jurassic Hanifa-sourced oils are present in both Jurassic and Cretaceous reservoirs.

The Hanifa sourced-oils exhibit relative thermal maturity differences between fields and by reservoir age. In general, reservoired-oils (Arab C, Arab D, Araej, Izhara, and Uwainat reservoirs) from the Dukhan, Maydan Mahzam, and Bul Hanine fields have higher relative thermal maturities than reservoired-oils from Al Rayyan, Al Shaheen, and Idd El Shargi fields. For a particular field, the relative thermal maturity of the oil appears to be related to stratigraphy, with the least mature oil in the youngest reservoir, and oil maturity increasing with reservoir depth. This is best observed in the Idd El Shargi field where the oil is least mature in the Cretaceous Shu'aiba and Jurassic Arab C reservoirs, and becomes more mature in the older (deeper) Arab D and Uwainat reservoirs.

The occurrence of relatively higher maturity oils in deeper reservoirs (Arab D, Uwainat, Izhara) suggests that the reservoirs were filled from top to bottom. In the Eastern Salt Province fields, the Hanifa source rock maturity increased from early mature to peak mature since 50 Ma. During this time, the deeper Izhara and Uwainat reservoirs of the Eastern Salt Province fields were charged with higher maturity oils. The close correspondence of the relative maturity of the oils in these fields with the maturity of the Hanifa source rock at present-day, indicates that the oils were generated in the thick, rich Hanifa kitchen to the south of Qatar. The occurrence of these older reservoirs in a structurally higher position than the thermally mature Hanifa source rocks located in the adjacent structural lows, suggests that hydrocarbons charged laterally into the deeper, older Uwainat and lzhara reservoirs located on the structural highs.

Hanifa-sourced oils in the Jurassic Arab reservoirs of northern Qatar contain relatively low-maturity oils. The presence of these oils is consistent with local generation from the pod of thin, rich Hanifa source rock (up to 20 feet thick with total organic carbon values up to 10.0%) that occurs north of the Qatar Peninsula. At 50 Ma these thin, rich source rocks were immature and did not generate hydrocarbons. However, starting at 30 Ma and continuing to present-day, this area passed through the early phase of the oil window, and generated low-maturity oils that migrated into the Arab reservoirs. The good correspondence between the maturity of the oils and the present-day Hanifa source rock supports the local migration of low-maturity oils.

Cretaceous-reservoired Jurassic oils (Kharaib, Shu'aiba, Nahr Umr, and Mauddud) from the Al Shaheen field are of higher maturity. The Hanifa source rock in this area is immature at present-day. Thus, the higher maturity oils observed in Al Shaheen most likely migrated from the deeper, mature Hanifa source kitchens located to the south. These oils most likely migrated laterally through porous Arab carbonates up the flanks of the Qatar Arch from the southwest, south, and southeast and then vertically into the Cretaceous reservoirs through dissolution features in the Hith evaporite.

New Paleozoic and Mesozoic petroleum systems, Saudi Arabia (IPTC 10440)

Hakami, A.M., S.T. Abdelbagi, M.A. Abu-Ali and A.S. Ahmed (Saudi Aramco)

Data from recent exploratory wells suggests new Jurassic and Paleozoic petroleum systems, in addition to the well-known Silurian and Jurassic petroleum systems in Saudi Arabia. The new petroleum systems are discussed with respect to their hydrocarbon characteristics, genetic relationships and potential source rocks. The new Paleozoic oil has lacustrine characteristics and is confined to the Carboniferous-Permian Unayzah Formation. The analyzed hydrocarbons are paraffinic with high pour-point and characterized by high gravity (API). The new Jurassic source rock is assumed to be Callovian-Oxfordian in age and is believed to be the lateral equivalent of the Tuwaiq Mountain-Hanifa interval. The bulk data of the analyzed Hanifa oils shows low S, Ni, V contents, and high Pr/Ph ratios, which are quite different from typical Arab-Hanifa oils of eastern Saudi Arabian basins. Biomarker data of the new Jurassic oils suggest generation from an open-marine environment with continental organic matter input (similar to Rub' Al-Khali and onshore United Arab Emirates) rather than a highly restricted carbonate source rock, such as the Hanifa-Tuwaiq Mountain formations, which generated the Arabian Basin oils.

High-resolution 3-D basin model of North Oman's gas system (IPTC 10227)

Kindy, S. and S. Ochs (Petroleum Development Oman)

With increasing gas exploration activity in the Sultanate of Oman, a dedicated study of the lower Paleozoic gas petroleum system of North Oman was undertaken in 2004. The study area covers over 50,000 square kilometers and encompassed all the major gas discoveries in the Sultanate. The study provided a 'fresh' look at the input parameters used to define both the thermal and migration models for gas expelled from source rocks of the upper Nafun Group (570–545 Ma). The modeling results were calibrated against a recently analyzed geochemical dataset describing the distribution and typing of North Oman gases in the lower Paleozoic reservoirs.

A uniform basal heat flow of the range of 35–40 mW/m^2 was preferred based on the calibration of available paleothermal indicators including Vitirinite Reflectance measurements (VR), Apatite Fission Track Analysis (AFTA), and corrected present-data bottom-hole formation temperature (BHT) data. No thermal evidence was found in support of major rifting events. This is also supported by the lack of growth faults on the seismic section across the whole region. Alternatively, accommodation space was possibly created by subsidence in a foreland basin setting, as part of a regional compressional setting.

The modeled maturity trend of Nafun source rocks across the North Oman Salt Basins (NOSB) shows two key expulsion peaks reflecting the basin's high subsidence during deposition of the Cambrian-Silurian Haima Supergroup and the subsequent Mesozoic carbonates. The modeling highlights areas with different expulsion histories and its impact on the risking of gas charge across the basin. The migration model highlights two key findings. Firstly, the presence of a narrow (approximately 50 kilometer wide) migration shadow zone, identified along the deepest part of the Ghaba Salt Basin as a result of the presence of a thick section of Ara salt, supported by two dry deep wells previously drilled in this zone. Secondly, Haima-cutting faults and the presence of regional intra-Haima seals (Al Bashair and Mabrouk shale members) are identified as critical elements in providing access for a late (0–200 Ma) 'dry' gas expulsion that filled older traps. The results of this study are used to construct charge-risk segment maps for North Oman, and provide a basis for dry versus wet gas type predictions to prospective traps.

MIDDLE EAST STRATIGRAPHY

New vision of the Shu'aiba at a regional scale (IPTC 10659)
Al-Mehsin, K. and B. Pierson (ADNOC); D. Drysdale and G. Warrlich (Shell); G.P. Eberli (University of Miami) and H. Droste (Shell)

The regional integration of well data, seismic observations and published information from the southern part of the Arabian Peninsula has led to a breakthrough in understanding the stratigraphy and depositional history of the Shu'aiba Formation and in extracting implications regarding hydrocarbon prospectivity. The Shu'aiba Formation is composed of system tracts from two supersequences, and the following subdivision is proposed. (1) The Lower Shu'aiba contains a TST and HST of a supersequence (early Aptian, earliest late Aptian), while the Upper Shu'aiba is a LST prograding package of the next supersequence (late Aptian). The TST of the older supersequence is distributed more or less equally over the entire Shu'aiba province and the HST of the same supersequence is characterized by the development of the Bab Basin with a well-marked differentiation between basin and margins. An unconformity separates this supersequence from the LST of the next Supersequence during which new carbonate facies prograded into the Bab Basin. On the basis of this subdivision, we propose a new, unified stratigraphic nomenclature for the Shu'aiba.

Depositional facies associated with the two supersequence systems tracts are markedly different. Monotonous, widespread carbonate facies dominated the older supersequence. During the HST, organic-rich fine carbonates accumulated in the Bab Basin while rudist-rich facies lined and vertically enhanced the southern and western basin margin or developed as relatively large isolated platforms on the eastern slope of the Bab Basin. In the LST of the younger supersequence, new platforms prograded into the Bab Basin in a series of sublinear, regular clinoforms that grew either parallel to the pre-existing southern and western margins of the Bab Basin or in a series of concentric rings, away from pre-existing isolated platforms. Extracting the detailed sequence stratigraphy of the clinoforms and understanding reservoir quality, presence of intra-formational seals and trap configuration has allowed us to identify and predict areas of higher hydrocarbon prospectivity in the southern part of the Arabian Peninsula.

Seismic sequence stratigraphy and reservoir distribution of the Early Cretaceous Habshan Formation in the United Arab Emirates (IPTC 10450)
Al-Zaabi, N. (ADOC); C.J. Strohmenger, W.L. Soroka, J. Dervieux, M. Abdelsattar, R. Rosell and S. Ali (ADCO)

A team approach consisting of structural, sequence stratigraphy, inversion specialists, geologists and geophysicists enabled a successful interpretation of the Habshan reservoir potential. The Early Cretaceous Habshan Formation of Abu Dhabi was deposited on a broad carbonate shelf. In the eastern onshore region, this formation consists mainly of limestones and dolomites reaching thickness of more than 1,100 feet. The depositional environment ranged from shallow-water pertidal to deep-shelf basin. The Habshan Formation is part of the early transgressive sequence set of a second-order supersequence (top Upper Jurassic to top Habshan Formation), built by two second-order composite sequences. The lower second-order composite sequence comprises two third-order composite sequences (Habshan sequences Ha0 and Ha1), corresponding to the transgressive and highstand sequence sets. The upper second-order composite sequence is built by three third-order composite sequences (Habshan sequences Ha2, Ha3, and Ha4), corresponding to the lowstand (LSS), transgressive (TSS), and highstand (HSS) sequence sets. High-energy, shelf-margin ooid-skeletal grainstones are the main reservoir facies and show overall progradation towards the east.

Reservoir in Habshan sequences has proven hydrocarbon-bearing in several onshore fields. Using high-resolution 3-D seismic data, inversion, very recent fault detection tools, regional geologic control and seismic stratigraphy techniques, the Habshan Formation was successfully mapped. The main reservoir facies and potential prospects appear as low acoustic impedance anomalies with geometries consistent with modern-day oolite shoals. Using both structural and stratigraphic considerations, the porous Habshan layers identified in the interpretation were evaluated for hydrocarbon potential. This study improved our understanding of the Habshan reservoir distribution and allowed a better evaluation of the HC potential in this formation as a consequence several new leads were added to exploration portfolio.

Sequence stratigraphic analysis of the Shu'aiba Formation: implications for exploration potential in Qatar (IPTC 11027)
Hohman, J.C. (ExxonMobil); I.A.A. Al-Emadi and M.E. Zahran (Qatar Petroleum)

Carbonates of the Aptian Shu'aiba Formation are important hydrocarbon reservoirs in the Arabian Gulf area. Historically, production has been primarily from fields located along the margins of the Bab Basin, an intrashelf basin that formed during deposition of the Shu'aiba. The reservoirs in these fields are progradational packages of platform margin carbonates deposited during the late stages of Shu'aiba Platform accumulation. The location of the Bab Basin, and the associated productive Shu'aiba platform margin trend, can be illustrated with an isopach map of the Upper Shu'aiba. The Bab Basin is represented by an area of relatively thin, basinal Upper Shu'aiba carbonates. An additional area of thin basinal Upper Shu'aiba carbonates is located to the west of the Bab Basin, and marks the western margin of the Shu'aiba Platform. A third area containing a thin Upper Shu'aiba section is located to the north of the Bab Basin. This area is often interpreted as an extension of the Bab Basin. However, detailed sequence stratigraphic analysis by Qatar Petroleum and ExxonMobil indicates this area was not a basin, but rather was the result of uplift and erosion that truncates the Shu'aiba Platform section. This truncation of the Shu'aiba Platform is important as it sets up a new play trend within the interior of the Shu'aiba Platform far from the traditional productive trend of platform margin carbonates surrounding the Bab Basin to the south.

A detailed sequence stratigraphic analysis of the Shu'aiba Formation reveals a complex internal stratigraphy consisting of relatively thick platform carbonates that thin rapidly into the adjacent basins. Superimposed upon this complex internal stratigraphy is the additional complication of uplift and erosion that has beveled much of the platform section to the north. Regionally the top of the Shu'aiba Formation is a recognized unconformity marked by widespread exposure. However, this study further documents truncation of section at the unconformity.

Distinguishing depositional thinning of the Shu'aiba Formation from its erosional truncation is the key observation in identifying the new platform interior play. In order to make this distinction, detailed sequence stratigraphic analysis of the Shu'aiba and the overlying Nahr Umr formations was utilized. A cross-section illustrating the distinguishing characteristics of depositional thinning versus erosional truncation is shown in the presentation. The southern end of the cross-section is an example of depositional thinning at the Bab Basin margin of the Shu'aiba Platform. Note the thinning carbonate packages that become increasingly more argillaceous into the basin. Just as importantly, note the thinning (onlap) of the Nahr Umr section onto the platform. This is characteristic of the basins adjacent to the Shu'aiba Platform. These basins contain a relatively thick Nahr Umr section that thins over the platform. Conversely, the northern end of the cross-section is an example of erosional truncation. Note the beveling of the Upper Shu'aiba section exposing progressively older Shu'aiba beneath the unconformity. Also note that overlying the truncated Shu'aiba section is a relatively thin Nahr Umr section. This combination of thin Shu'aiba overlain by thin Nahr Umr is in direct contrast to the basin area where thin Shu'aiba is overlain by thick Nahr Umr. The presence of thin Shu'aiba (erosional truncation) in conjunction with a thin Nahr Umr section (onlap) indicates that this area was a topographic high following Shu'aiba deposition and continuing through deposition of the Nahr Umr Formation.

The result of this topographic high is the juxtaposition of the Nahr Umr Formation, a regional seal, immediately overlying a porous Shu'aiba section that is older than the productive Shu'aiba section in the traditional platform margin play area. In fact, the porous Shu'aiba section of the truncated platform interior trend is generally nonporous in the platform margin trend. Analysis of core and well log data indicates that most of the effective porosity of the Shu'aiba Formation is moldic porosity where rudist skeletal material has been dissolved. The excellent moldic porosity suggests a preponderance of rudist material in the lower portion of the Upper Shu'aiba preserved beneath the unconformity, possibly even rudistid buildups. It is the positioning of porous, rudist-bearing carbonates in the older part of the Upper Shu'aiba section directly beneath the sealing Nahr Umr shale that entraps hydrocarbons in Shu'aiba reservoirs in the North Dome area of the Qatar Arch. The presence of these hydrocarbons far from the traditional productive trend of platform margin carbonates shows that exploration in the Shu'aiba need not be restricted to the narrow fairway of platform margin carbonates that surround the Bab Basin. This study shows that the application of state-of-the-art interpretation techniques and high-resolution data is a powerful method for identifying new opportunities within mature exploration provinces.

Sequence stratigraphy of the Jurassic Hanifa Supersequence: a stratigraphic framework for understanding the distribution of marine restricted source rocks in the Hanifa intrashelf basin (IPTC 11026)

Hohman, J.C., J. Guthrie (ExxonMobil); I.A.A. Al-Emadi and M.E. Zahran (Qatar Petroleum)

Deposits of the Hanifa Supersequence represent the filling of the restricted-marine, intra-shelf Hanifa Basin during Jurassic time. The Hanifa Supersequence is a distinctive source rock-bearing section bounded by prominent regional unconformities that includes the Hanifa Formation along with the Tuwaiq Mountain Formation. This Hanifa-Tuwaiq Mountain section can be subdivided into four sequences. In ascending stratigraphic order, these sequences are: (1) Tuwaiq Mountain Sequence; (2) Hadriya Sequence; (3) Lower Hanifa sequence; and (4) Upper Hanifa Sequence. Each of the sequences has a similar distribution of depositional thickness. The thickest deposits are located in the western part of the study area in Saudi Arabia, and thin to the east in the central part of the study area in Qatar. The deposits thicken again in the eastern part of the study area in Abu Dhabi. An important exception to this general trend in the distribution of the deposits is truncation of the section due to erosion at the unconformity that caps the supersequence. Significant amounts of the youngest two sequences are removed by this truncation over much of the study area. The youngest sequence, the Upper Hanifa Sequence is particularly impacted by this truncation and is only preserved in the northeast part of the study area.

Each of the four sequences represents a discrete episode of carbonate platform development and progradation into the Hanifa Basin. Each sequence consists of thick platform deposits of skeletal-oolitic grainstone, packstone and wackestone that grade basinward into organic-rich mudstone. The thick accumulation of grainstone, packstone and wackestone represent stacked carbonate shoal complexes that individually grade-off the platform into organic-rich mudstone, which characterizes deposition in the restricted basin adjacent to the platform. The sequences can be further subdivided into a lower Transgressive Systems Tract and an upper Highstand Systems Tract, with the boundary between the two marking the maximum flooding surface of a sequence. The Transgressive Systems Tract section is relatively thin forming a gentle ramp from platform to basin. The Highstand Systems Tract section, in contrast, is typified by relatively thick platform deposits that thin markedly into the basin forming a steepened platform margin. The basinal deposits of both systems tracts contain source rocks. However, the majority of the source rock appears to be associated with the Highstand Systems Tract section. This Highstand source-rock section together with the lesser, yet still significant, transgressive source rock section results in a composite source rock section centered upon the maximum flooding surface of a sequence.

An integrated study using well log, core and geochemistry data was conducted to map the distribution of these source rocks and their richness (OTOC - original total organic carbon content). Areas of thick, rich source rock occur where the composite source rock sections of individual sequences within the Hanifa Supersequence are stacked together. Additionally, significant amounts of rich source rock may occur in relatively thin intervals where only a single composite source section from an individual sequence is present.

A net source thickness map for the Hanifa Supersequence shows that up to 145 feet of laminated, organic-rich mudstone occurs in stacked composite source sections in the Hanifa Basin located partly in the southeastern portion of Qatar but also extending into offshore Abu Dhabi and the southern part of the Qatar peninsula. Furthermore, limited well data suggests that composite source sections in the basin are also stacked at locations to the west in Saudi Arabia where the source rock is approximately 110 feet and 145 feet thick. The distribution of these composite source rock sections is controlled by the location of platform development in the individual sequences with the source rocks deposited in the basins adjacent to the platform. Furthermore, platform location typically changed with time from sequence to sequence as the Hanifa Basin filled. Consequently, the location of the individual source rock sections also changed.

The distribution of average OTOC for the Hanifa Supersequence shows that organic enrichment occurs both in areas where there are stacked source rock sections (thick-rich) and in areas where a single composite source section (thin-rich) is present. Average OTOC values greater than 8.0% occur near the area of thick source rock located in the offshore/onshore region of Abu Dhabi southeast of Qatar. Conversely, thin organic-rich rocks (OTOC > 8.0% occur in eastern and northern Qatar. This documents that the presence of effective source rocks are not just related to areas of thick source rock accumulation and may be more widespread than typically envisioned. The improved understanding of source rock distribution and richness derived from this study has led to increased understanding of the Hanifa hydrocarbon accumulations in both the Jurassic and Cretaceous reservoirs in the Arabian Gulf area.

Correlation of the Dalan/Kangan Formation between the Zagros and offshore Iran-Impact on lateral changes in reservoir facies and quality (IPTC 10165)

lnsalaco, E. (Total); M. Loftpour, M. Moallemi and M. Kamali, (RIPI, Iran); C. Fraisse, P. Thiry-Bastien, M. Sudrie, P. Masse and M. Lescanne (Total)

The Dalan and Kangan formations, and Khuff Formation contain major reservoirs in Iran and the rest of the Middle East Gulf region, including some of the world's greatest gas reserves. The reservoir facies of these formations developed on a large regional carbonate platform, which had a very low topographic relief. This large geographic extent of the platform system is responsible for the development of very extensive facies tracts. In order to encounter major facies changes, large areas need to be investigated. This is often not possible in detailed reservoir-scale studies. In such cases, integrated models that extend from proximal positions to more oceanward locations are difficult to apply. In order to address these issues a major multidisciplinary and multiscale subsurface study has been launched on a large database including fields from onshore and offshore Iran. The aims are to better understand the facies distributions, sequence stratigraphic architecture and the regional reservoir development.

Twenty-two facies have been recognized including massive to laminated anhydrite, mudstone with anhydritic nodules, dolobreccias, green shale, massive to bioturbated mudstone, laminated dolomudstone, coarse lithoclastic grainstone, bioclastic grainstones, oolitic grainstones, peloidal grainstones, and thrombolitic limestone. These facies have been interpreted in terms of depositional environment including: evaporitic flats (shelf supratidal/intertidal to subtidal setting), tidal flats (intertidal to supratidal setting, with numerous subenvironments such as beach ridges, intertidal flats, tidal channels), subtidal lagoon (subtidal setting), leeward shoals (subtidal - intertidal setting), oolitic to oobioclastic shoal belts (subtidal to intertidal setting), composite sandwave constructions (subtidal setting), and middle shelf deposits (subtidal setting).

From the Dalan K4 through to the Kangan K1 significant changes in platform type/geometry, facies organization and climate occurred. Consequently, different depositional models need to be created for each of the major stratigraphic intervals. Conceptual geological models have been constructed for the large-scale stratigraphic architecture, sedimentological organization and the paleoecological systems. The correlations show significant changes in sedimentological and reservoir facies across the study area, which are not evident at smaller scales. These large-scale geographic and stratigraphic facies trends provide a regional framework which can then be used to help constrain reservoir-scale studies.

MIDDLE EAST STRUCTURAL GEOLOGY AND TECTONICS

Structural styles and tectonic evolution of onshore and offshore Abu Dhabi, United Arab Emirates (IPTC 10646)

Johnson, C.A. and T. Hauge (ExxonMobil); S. Al-Menhali (ADNOC), S. Bin Sumaidaa (ADCO); B. Sabin and B. West (ExxonMobil)

Brittle deformation of carbonate reservoirs was characterized by applying advanced visualization and interpretation techniques to 18 recent 3-D seismic surveys in Abu Dhabi. The excellent data quality afforded a unique opportunity to integrate the broad range of observed structural styles and detailed structural geometries into a unified tectonic model. This resulted in a better and more thorough definition of the structure and hydrocarbon distribution of Abu Dhabi in the context of the entire Arabian Platform. The observed structures resulted from gentle basement inversion, salt-tectonics and detached thrusting. The N- and NE-trending anticlines that form the giant onshore fields grew during Late Cretaceous, basement-involved foreland inversion. Systematic sets of remarkably linear, small-offset conjugate fault zones, oriented approximately N75^{o}W and N45^{o}W, cross the anticlines at high angles to the axial traces. The consistent orientations and shear sense of the fault zones suggests they resulted from regional WNW-ESE compression, which also drove Late Cretaceous inversion and fold growth. Development of the salt-related anticlines was influenced by the same Late Cretaceous compression, as well as multiple episodes of salt movement. Both sets of anticlines share the regional fault trends, but the salt-related fault zones have more variable orientations and timing. Mechanical stratigraphy clearly influences fault zone spacing, offset, and segmentation, both laterally and vertically. Interpretations of the fault zones as single fault planes underestimate their geometric complexity. The key to unraveling and communicating the geometric complexity is making use of a combination of data optimization and advanced 3-D visualization and interpretation techniques. Quantification of the orientations, segmentation, offset magnitudes, and spacing of the fault zones provides a foundation for defining their implications for fluid flow within the reservoirs.

Regional structural analysis and kinematic framework of the Euphrates Graben, East Syria (IPTC 10904)

Koopman, A. (Shell)

The Euphrates Graben in East Syria is a "hidden" intra-cratonic rift-basin, some 120 km wide, formed by crustal extension in the middle to Late Cretaceous. Prerift clastic reservoirs, differentially subsided along a complex pattern of faults, are charged from synrift source rocks and covered by a thick late synrift to postrift seal. An early synrift waste rock unit exerts a decisive control on trap size in a large part of the basin. Static and dynamic field models, as well as positioning of wells have proven to be critically dependent on the definition of faults, and the characteristics of fault geometries. Structural geological data from a variety of seismic attribute images were compiled and synthesized into a consistent and geomechanically viable, regional structural framework of the basin and its fields, in order to better define its hydrocarbon volumes, to enhance hydrocarbon recovery, and to improve subsurface targeting of wells. The fault pattern of the rift basin is organized according to a number of highly interlocking but laterally persistent trends, most of which are inherited from already existing anisotropies in structural basement and its prerift overburden. A diffusely distributed and limited component of northerly trending, left-lateral shear appears to be a major contributor to structural complexities within the basin. Relatively simple interpretation concepts of composite faulting, consistent with the regional framework and underpinned by experimental models and outcrop analogues, have contributed to a better understanding of the basin and its fields.

Inversion and folding of the southern unelevated folded belt in North Iraq (IPTC 11015)

Marouf, N. (Al-Zab Petroleum Consulting Bureau) and M. Sh. Al-Kubaisi (University of Baghdad)

The southern part of the unelevated folded belt in Iraq is characterized by the presence of long, relatively narrow NW-trending anticlines separated by broad, flat-bottom synclines. The northeastern flanks of all the exposed anticlines suffered from thrusting parallel to the axial trends of the major anticlines. The surface thrusts always initiate within the salt bearing horizons of the lower-middle Miocene mobile sequence and migrate up-stratigraphy to the post-middle Miocene upper competent sequence. The pre-Miocene lower competent sequence is always affected by at least two high-angle major reverse faults dipping toward each other, and trending parallel to the axial trend of the major anticlines.

Geometrical analyses based on surface and subsurface (seismic and drilling) data elucidate the following interpretations. The major anticlines are fault-propagation folds formed in response to the thrust movements on the major reverse faults. Thickness variations of the

Maastrichtian (Upper Cretaceous) strata across the major reverse faults, implies that these reverse faults were actually normal faults that formed grabens and half-grabens during the Maastrichtian time. Reactivation of the extensional movements on these grabens during the early and middle Miocene times resulted in the restricted deposition of the lower and the middle Miocene rocksalt facies of both the Dhiban and Fatha formations. A compressive stress field acting during and after the Pliocene resulted in inversion of movements of the former normal faults and converted them into reverse faults, and also resulted in the formation of the major and minor structures of the studied area. The onlapping of the Mugdadiah-Bai-Hassan sequences over the top of Injanah Formation implies that the contraction and the elevation of the major anticlines started at the onset of the Pliocene. This contractional phase was coaxial with the former extensional phases, and both were oriented in a NE-SW direction. The kinematics and dynamics of faulting and folding, in addition to the influence of the mechanical stratigraphy, were studied in detail.

Tectonic and subsidence controls on Jurassic and Triassic stratigraphy and depositional patterns of the Arabian Plate (IPTC 10389)

Willan, C.G., G.J. Grabowski Jr. and L.A. Roehl (ExxonMobil)

The margins of the Arabian Plate evolved as passive and passive-transform margins of the Tethys Ocean during the Triassic and Jurassic periods. Regional upwarps are recorded as plate-wide unconformities with variable amounts and distributions of erosion. Subsequent thermal-tectonic subsidence created accommodation space, allowing onlap onto unconformities and preservation of eustatically-driven sequences. The Jurassic and Triassic section consists of 14 second-order sequence sets, each with two to six third-order sequences typified by transgressive-to-highstand shoaling-upward systems tracts. Third-order sequence boundaries show little erosion or onlap.

The Lower and Middle Triassic are characterized plate-wide by carbonates. The Upper Triassic is shallow-marine and non-marine (Minjur Formation) clastics on the southern Arabian Plate and more continuous carbonate-evaporite deposits on the northern Arabian Plate. An unconformity below the Minjur Formation cuts into the carbonates across the northern Arabian Plate and the Qatar Arch. Another unconformity erodes the Minjur Formation, and together these two unconformities cut through the Triassic on the southern margin of the southern Arabian Plate. These unconformities are related to uplift when India started to rift away from Arabia.

Liassic (Lower Jurassic) deposition started in the northern Arabian Plate and progressively lapped onto Triassic rocks from the north, covering the Qatar Arch last during the Toarcian. The Gotnia Basin, a starved basin with thin deep-water sediments, formed in the northern Arabian Plate in the Middle Jurassic. The Gotnia Basin was rimmed by oolitic carbonates, as was a zone which extended to the southwest along the present-day Arabian Gulf. These shoals formed a barrier southwest of which were platform-interior carbonates, in some cases organic-rich. The paleogeography changed in the Kimmeridgian, when evaporites filled the Gotnia Basin and intercalated carbonates and evaporites of the Arab and Hith formations covered the southern Arabian Plate. An unconformity occurred in the Tithonian, with deep erosion regionally in southeastern Arabia and on isolated salt structures across the southern Arabian Plate.

MIDDLE EAST EXPLORATION CASE STUDY

Exploration history of the intrasalt carbonate stringers in the South Oman Salt Basin (IPTC 10407)

Al-Abry, N.S. and H. Al-Siyabi (Petroleum Development Oman)

Carbonate intrasalt stringer exploration in the South Oman Salt Basin (SOSB) started with the accidental discovery, in 1976, of moveable oil in Nasir-1. This started the first phase of exploration of the Cambrian stringers and focused on the Birba and Dhahaban areas. Despite significant volumes addition during this campaign, the stringer play proved to be complex. Limited knowledge of the stringers depositional systems and diagenetic history made predicting reservoir quality difficult and explaining production behavior next to impossible. Difficulty in delivering expected reserves forced the play to become dormant in 1986. The second phase of stringer exploration started in 1988 after a review of deep exploration opportunities that highlighted the play potential outside the proven Birba-Dhahaban area. All wells drilled during this phase failed to discover commercial hydrocarbon accumulations, forcing the play to become dormant for the second time. This short-lived campaign, however, led to the Cambrian Al Noor Athel discovery, which kicked-off an Athel exploration campaign that lasted until 1997. Interest in the Ara stringers was revived after the discovery of oil in Harweel Deep-1 in 1997. Continuous success in the Harweel area has maintained interest in stringer exploration to this day (UR Oil Expectation at 53 million m^3) and led to fast-track the development of some of the Harweel discoveries (currently producing more than 3,000 barrels of oil/day), thereby positioning the stringers to significantly contribute to Petroleum Development Oman's future oil production. Continued stringer exploration in the coming years will require expanding the play outside the current proven fairway, which will not be without challenges. Success in this upcoming phase of exploration will require significant advances in the following areas: seismic imaging, prediction of reservoir occurrence and hydrocarbon charge history.

Exploring the "Empty Quarter": early experience and lessons of a new upstream venture in Saudi Arabia (IPTC 10695)

Allman-Ward, P. and W. Voggenreiter (South Rub AI-Khali Company)

Under the terms of the Upstream Project Agreement ratified in November 2003, the South Rub Al-Khali Company Limited (SRAK) has entered into an agreement with the Kingdom of Saudi Arabia for the exploration, appraisal, development and production of non-associated gas, condensate and natural gas liquids in Contract Areas 1 (Blocks 82–85) and 2 (Blocks 5–9) in the South Rub' Al-Khali Basin of Saudi Arabia. SRAK is an Incorporated Joint Venture between Shell (40%), Saudi Aramco (30%) and Total (30%), with Shell providing the technical lead. Exploration activities, under the terms of the Upstream Project Agreement, are governed by a first five-year exploration term and two subsequent five-year exploration periods undertaken at the option of SRAK. Work commitments for the first exploration term encompasses a major seismic acquisition program of 16,000 km of 2-D data and the drilling of seven exploration wells. The exploration acreage covers an area of approximately 210,000 square km, equivalent to 10% of Saudi Arabia's land area. SRAK's exploration efforts will be focused on the Paleozoic reservoirs. In contrast to the hydrocarbon-rich tracts within the Saudi Aramco Reserved Area some distance to the north, the remote South Rub' Al-Khali Basin is only lightly explored, and the presence of a working (Paleozoic) hydrocarbon system has yet to be demonstrated. Eighteen months into the first exploration term, this paper focuses on the venture related as well as technical challenges that are being faced and how they are being addressed.

A regional comparison of Khuff and Arab reservoir potential throughout the Middle East (IPTC 10222)

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

Carbonate reservoirs from producing oil and gas fields have extreme ranges of porosity and permeability, both locally, within a single reservoir zone, and in terms of average values for entire reservoir zones. This study describes the latter type of variation for two major reservoir formations in the Middle East and lists the factors that seem likely to account for the striking overall differences between these units.

Reservoir Facies Prediction of the Mishrif Formation, Upper Cretaceous, United Arab Emirates (IPTC 10426)

Soroka, W.L., F.S. Al-Shekaili, C. Strohmenger, M.A. Sattar, A. Al-Aidarous and S.B. Sumaidaa (ADCO - Abu Dhabi Co. for Onshore Oil Operations)

Using an integrated interpretation approach, utilizing structural interpretation, attribute analysis, seismic stratigraphy, regional geology, acoustic impedance from inversion and well calibration, a model of potential Mishrif reservoirs was developed for the area of exploration interest. The integrated interpretation resulted in a Mishrif model that was consistent with regional geology, local stratigraphy, well control and detailed geophysical studies and interpretation. Based on the final integrated interpretation a new seismic program was proposed and justified. The new seismic will provide essential information over potential leads and prospects to better quantify the structural size and help confirm the presence of porous reservoir facies.

Tectonostratigraphic development and prospectivity of the pre-Khuff succession in the southern Arabian Peninsula (IPTC 10532)

Spaak, P. and A. Bell (Shell)

Significant quantities of hydrocarbons have been discovered in the predominantly clastic, pre-Khuff reservoirs of Saudi Arabia and Oman. Exploration for gas in the deeper parts of the Rub' Al-Khali basin is currently being undertaken by several companies. The hydrocarbon systems, both known and speculative, in this area, are influenced by the basement morphology. The late Proterozoic amalgamation of the crystalline basement terranes has resulted in a heterogeneous base to the sedimentary section. The reactivation of this basement coupled with eustatic sea-level variations and global climate changes has resulted in the tectonic-stratigraphic control, which has profoundly influenced the development of source rock facies, potential reservoirs and regional seals.

Two proven source rock systems have contributed to the oil and gas accumulations in the region. The oldest of these, the Ediacaran-Cambrian aged Huqf system is currently known only from Oman. Source-rock deposition is controlled to a large degree by an early transtensional rift system, which has also resulted in the deposition of the Cambrian-aged Hormuz (Ara) salt. The second major source rock system is the base Silurian-aged Qusaiba source rock. While this source rock is correlated globally with a post-glacial flood event, there is evidence that basement has subtlely influenced deposition and facies.

The primary reservoir units of the pre-Khuff are dominantly clastic, although carbonate reservoir units are known from the Cambrian of Oman. The main clastic units can be broken into three groups: (1) post-Angudan unconformity sediments which are interbedded with Upper Cambrian and Ordovician flood events and lying stratigraphically deeper than the Silurian source rock; (2) Silurian to Carboniferous aged clastics that are older than the Hercynian unconformity; and (3) post-Hercynian, pre-Khuff sediments, representing the deglaciation subsequent to the Carboniferous-Permian glaciation and coincident with the rifting associated with the opening of the Tethys Ocean. In all three sedimentary groups, the complex interplay of basement structuration, eustacy and climate change has resulted in the sedimentary patterns described.

RESERVOIR SEISMOLOGY

Rock property prediction using multiple seismic and geologic attributes provides insight to field development for a large United Arab Emirates field (IPTC 10595)

Al-Menhali, (ADNOC) S., J.S. Schuelke (ExxonMobil) and B. Soroka (ADCO)

High-quality 3-D seismic data over a large United Arab Emirates field, combined with high-end geophysical techniques, resulted in spectacular porosity detail from seismic data over this carbonate field. By using special post-stack filtering techniques to improve data continuity and discontinuity, two optimal data sets were generated. One data volume was optimized for structure and stratigraphic interpretation and the other for event mapping and quantitative seismic attribute analysis. A multi-attribute calibration method was used to estimate the porosity from the seismic data. Attributes used include seismic and geologic or interpretative attributes. The result was a porosity prediction that was 20% improved over the traditional single attribute approach, as measured on hidden well data. The predicted porosity volume provided high-quality detail of reservoir heterogeneity and was very useful in understanding flood-front advance in the platform interior and flow patterns in the clinoforms. In addition, the seismic-porosity volume provides a means to place future wells to tap bypassed oil and to optimize the location of planned injector and producer zones.

Impact of high-quality seismic on the field development of a mature supergiant Cretaceous carbonate field, onshore Abu Dhabi (IPTC 10745)

Boekholt, M., R. King, A. Al-Hamedi and F. Al-Shekaili (ADCO)

The first field discovered in the ADCO (Abu Dhabi Co. for Onshore Oil Operations) concession came on stream in 1963 and is one of the largest hydrocarbon accumulations in the United Arab Emirates. In 40 years of production, about 700 boreholes penetrated the main reservoirs; however, virtually no seismic was acquired over the field. In 2001, the decision was taken to acquire high-quality 3-D seismic survey across the field after extensive field tests to optimize acquisition parameters and after incorporation of the learnings on the 3-D seismic imaging in other ADCO fields. The actual seismic acquisition took two years over an 1,800 square km area with 640 fold coverage in 12.5 m by 12.5 m bins. It resulted in an extremely high-quality dataset. Extreme care was given in processing to preserve amplitudes and frequencies to enable quantitative seismic attribute analysis. The seismic data offers a unique opportunity to study a Middle East carbonate reservoir after 40 years of production at an unmatched resolution of 100 Hz bandwidth at target level at a 3.0 km depth. Conventional interpretation started in conjunction with advanced seismic analysis (inversion and forward modeling) while the data processing was still ongoing. The studies indicate that information on structure, rock properties and fluid effects can be extracted from the seismic to a much greater detail than possible in any other seismic dataset of ADCO. So far, immediate impact on field development was obtained in three ways. First, several fault systems were observed and tied to the main orogenetic phases of the Arabian Plate, including Paleozoic and Proterozoic trends. Faults can be observed on seismic down to a throw of 5 feet and were confirmed by drilling results. Second, depositional geometries and stacking patterns within the main carbonate reservoirs were detected. These were used to develop new insights into the reservoir depositional cycles. Third, flat spots at the edge of the field and water-indicating isochron values around water injectors in the main reservoirs strongly suggest that fluid effects appear to be visible. Analysis on well and seismic data indicates that the effects of porosity and fluid change on the acoustic impedance can be separated in the studied carbonate reservoirs.

Obtaining permeability from seismic data-a new breakthrough in carbonate reservoir modeling (IPTC 10577)

Bracco Gartner, G.L. and P.D. Wagner (Shell); G.T. Baechle (University of Miami); Y.-F. Sun, (Columbia University); R. Weger, G.P. Eberli and W. Asyee (University of Miami); H. Hillgartner, K. van der Kolk, J. Leguijt, M.R. Nasser and J.L. Massaferro (Shell)

Shell's Carbonate Team has been developing a method in which post-stack seismic can be used to estimate average interval matrix permeability in carbonates. The foundation of the technique is a new model, which describes quantitative relationships between sonic velocity, porosity and permeability. This model relates a pore shape factor from the poro-elasticity theory with permeability from lab measurements. This pore shape factor describes the 3-D pore structure and can be extracted from inverted post-stack seismic data. Additionally, this factor relates to pore connectivity and, therefore, to permeability. After the concept was tested and successfully proven on plug scale, the first implementation focused on a large carbonate field in the Middle East. This accumulation had all the ingredients to perform a full-field test of the concept: good thickness for multiple seismic reflections, matrix-dominated permeability, single mineralogy (calcite), superb seismic data and enough wells with good compressional and shear wave sonic logs. Introducing pore structures in the characterization of carbonate reservoirs from acoustic data helps resolve the ambiguity in porosity/permeability prediction. In the test case, we have demonstrated that: (1) the new rock property prediction is much more accurate than properties predicted by commercial inversion packages; (2) pore structure can be extracted from 3-D post-stack seismic; (3) a permeability indicator can be estimated from inverted seismic; and (4) a permeability indicator volume proved to produce a superior history match against a permeability model constructed from extensive well data.

Production-induced deformations outside the reservoir and their impact on 4-D seismic (IPTC 10818)

Kristiansen, T.G., O.I. Barkved, K. Buer and R. Bakke (BP)

A 4-D seismic data was acquired over the Valhall field located in the chalk province on the Norwegian continental shelf. The field is monitored with 4-D seismic and is the first field in the world to be monitored with permanent installed cables at the seafloor. This concept, including 120 km cables trenched into the seafloor above the field, is providing seismic on demand for reservoir management purposes and is called "Life of Field Seismic". This paper will focus on: (1) the seismic observations of production-induced deformations outside the reservoir at Valhall; (2) review the theory behind the deformations, how they impact the seismic velocities and the use of 4D seismic for reservoir monitoring. The paper will present integration of relevant theories, numerical modeling and results from laboratory experiments.

The work presented should have applications to other fields where even limited reservoir compaction will take place. How significant the reservoir compaction will be is dependent on the structural geometry, rock properties of the surrounding rock, reservoir thickness, the compressibility of the reservoir, the pore pressure depletion, and if any weakening of the rock takes place during secondary or tertiary recovery processes. The methods presented in the paper can also be used to improve the uniqueness of the static geologic model, the dynamic flow model and the geomechanical model and, hence, result in a more unique history match of the reservoir as well as improved future prediction.

The main technical contributions from this paper are a detailed review of theory, laboratory and field data of relevance from a well-instrumented field under seismic surveillance. The paper will also outline how integration of geophysics, geology, geomechanics and reservoir engineering can produce better reservoir performance prediction based on new workflows. The paper will also show how a problem of production induced deformations outside a reservoir, with corresponding velocity changes, may be used as an advantage in reservoir performance prediction in the future.

3-D OBC seismic survey design for multiple objectives (IPTC 10730)

Painter, D.J., S. Al-Sharif (ADMA-OPCO); M. Qaradeh and M. Al-Kaabi (ADNOC); K. Furuya (Zadco); K. Belaid (ADMA-OPCO) and A. Al-Shateri (Zadco)

Abu Dhabi Marine Operating Co. (ADMA-OPCO) and Zadco are performing an intensive 3-D OBC (Ocean Bottom Cable) seismic survey in offshore Abu Dhabi with the twin primary objectives of defining the Thamama reservoir in an undeveloped structure, and defining the overlapping Mishrif reservoir in a currently producing field. The value of the survey is increased by the reservoir characterization information that can be extracted from the seismic data. The structural Thamama reservoir target has different seismic acquisition geometry requirements to those of the stratigraphic Mishrif reservoir. OBC acquisition has a huge range of potential geometries and value and costs. This paper describes the processes that were used to reconcile the technical and economic conflicts.

Experience from a previous 3-D OBC survey highlighted the generic problems in the area: (1) source-generated noise; (2) strong multiple interference; and (3) acquisition footprint. New survey design had to overcome these plus it has to deliver high-resolution data (80 Hertz at target level) to attain the stratigraphic and reservoir characterization objectives within a finite budget. Team identification of key objectives was critical for the implementation of the successful survey design. Analysis and review of various modeling processes (acquisition geometry, seismic processing responses, acquisition economics) guided the team to an affordable solution that meets the geophysical objectives of a high-quality, high-resolution survey. The process has provided a methodology that will be used as a basis for evaluating of cost versus quality in future surveys.

New 3-D seismic interpretation methods to characterize fractured gas reservoirs (IPTC 10946)

Reeves, J.J. (GeoSpectrum)

Reservoir fractures are predicted using multiple azimuth seismic lineament mapping in the Lower Dakota reservoir section. A seismic lineament is defined as a linear dislocation seen in a time slice or horizon slice through the seismic volume. For lineament mapping, each lineament must be recognizable in more than one seismic attribute volume. Seismic attributes investigated include: coherency, amplitude, frequency, phase, and acoustic impedance. We interpret that areas having high seismic lineament density with multidirectional lineaments are associated with high fracture density in the reservoir.

Lead areas defined by regions of "swarming" multidirectional lineaments are further screened by additional geologic attributes. These attributes include: (1) reservoir isopach thickness, indicating thicker reservoir section; (2) seismic horizon slices, imaging potentially productive reservoir stratigraphy; and (3) a collocated cokriged clay volume map for the Lower Dakota computed from near trace seismic amplitude (an AVO attribute) and a comprehensive petrophysical analysis of the well data to determine discrete values of clay volume at each well. We interpret that clean/low clay reservoir rock is brittle and likely to be highly fractured when seismic lineaments are present.

A gas-sensitive AVO seismic attribute, near trace stacked phase minus far trace stacked phase, phase gradient (an AVO attribute first developed by GeoSpectrum), is used to further define drill locations having high gas saturation. The importance of this attribute cannot be understated, as reservoir fractures enhance reservoir permeability and volume, they may also penetrate water saturated zones in the Dakota and/or Morrison intervals and be responsible for the reservoir being water saturated and ruined. Seismic interval velocity anisotropy is used to investigate reservoir potential in tight sands of the Upper Dakota up hole from the main reservoir target. We interpret that large interval velocity anisotropy is associated with fracture related anisotropy in these tight sands.

Results from a four well drilling program to test GeoSpectrum's fractured gas reservoir prospects show that the fracture detection methodology is ready to be applied on a commercial basis.

Reservoir monitoring with seismic timeshifts: geomechanical modeling for its application in stacked pay (IPTC 10511)

Schutjens, P. (on behalf of the Shell Mars/Europa timelapse seismic study team)

Production-induced depletion of hydrocarbon and water reservoirs leads to deformation, compaction, displacements, and stress changes in the reservoir, as well as in the surrounding rock. Shell's geomechanical finite-element computer program was used to simulate this for the depletion of stacked oil-saturated reservoir sands from the Mars basin in the Deepwater Gulf of Mexico, USA. 3-D quantitative insight was obtained in the response and mechanical interaction of depleting sands and surrounding mudstones as a function of production. The calculated deformation and stress change were used to model changes in two-way travel time of vertically-propagating seismic P-waves. Comparison of our 3-D model results with repeat-seismic 2-D field timeshift data shows reasonable agreement. This confirms the value of integrating geomechanics in forward models of seismic timeshifts related to depletion, and may find application in reservoir fluid-flow monitoring with time-lapse seismic. Systematic variation of the depletion pattern in stacked sands of idealized lenticular shapes helped to understand some basic aspects of compaction-induced timeshifts, and revealed their potential and limitations in deep stacked-reservoir settings. Our Mars model of compaction-induced timeshifts needs further calibration to field data, and addition of the salt-sediment geomechanical interaction. However, already at this stage, our study suggests that forward models of compaction-induced seismic timeshifts can help to better interpret field observations of timeshifts, with a promise to detect undepleted compartments and fluid-flow barriers in producing reservoirs.

Assessing horizontal stress direction using seismic and borehole geometry data: study from Balam South field (IPTC 10551)

Umam, M.S. (PT Caltex Pacific Indonesia)

This study demonstrated the utilization of seismic data and borehole geometry to determine the horizontal stress direction in Telisa Formation, Balam South field in the Central Sumatra Basin, Indonesia. The Telisa Formation is one of the oil reservoirs in the Balam South field, where an enhanced oil recovery project has been initiated in this shale-sand reservoir. In the reservoir of interest, seismic attributes gave strong indication of the presence of natural fractures. Acoustic impedance data showed relatively lower magnitude in the suspected natural fractures zone. The decrease of the acoustic impedance magnitude was interpreted as corresponding to the decrease of the acoustic seismic velocity in the suspected fractured zone. Analysis of borehole shape from multi-arm caliper data in this field also supported the interpretation. The borehole shape is slightly elongated perpendicular to the interpreted maximum stress direction, giving indication of the presence of excess horizontal stress applied to the borehole from the maximum horizontal stress direction. Several other multi-arm caliper data were then acquired to confirm and calibrate the stress map for better interpretation result.

This study inferred the natural fractures orientation from seismic attributes to represent maximum horizontal stress direction. The interpreted map from the seismic data was then calibrated with the maximum horizontal stress orientation determined from the reconstructed borehole geometry. The final interpreted map of maximum horizontal stress direction was then used as a guideline for optimum hydraulic fracturing in the wells drilled in the waterflood project.

GEOPHYSICAL TECHNOLOGY

Optimal noise and multiple suppression on Arabian Gulf marine data (IPTC 10472)

Alai, R. (Anadarko)

This paper discusses some improved strategies for successful multiple estimation and suppression on very shallow-marine data recorded in various areas in the Arabian Gulf. Since the seabottom is extremely shallow in particular areas of the Arabian Gulf, the marine data that has been recorded contains numerous, very strong waterbottom multiples (from reverberations between seasurface and seabottom), which tend to create complex interference patterns with the primaries. As is generally known, multiples may become a major difficulty in the Arabian Gulf, in particular in seismic data interpretation including AVO analysis. This is because multiples may obscure crucial target structures and make optimal data interpretation – and therefore exploration – very complicated. However because the primary reflections are necessary for an accurate interpretation of the earth's subsurface, it becomes very critical to aim at improving strategies that can suppress multiples in the most effective and optimal way.

In shallow-water environments, surface-related multiple removal methods are very difficult to apply and are known to have problems. On the other hand, in some situations, the well-known prediction-error filtering has proven to be effective and successful. In this paper, the successful attenuation of multiples is illustrated on various datasets from the Arabian Gulf. The noise and multiples were attenuated sequentially. First, the noise was estimated systematically from the data and suppressed. This was followed by autocorrelation analyses on the prestack shot gathers to estimate sequentially different types and higher orders of multiples with multigate prediction filters. Furthermore, multileast squares algorithms were used to subtract all multiples simultaneously in the prestack domain. The simultaneous subtraction appears to provide a robust solution in these complex situations. Finally, some remaining multiples have been attenuated in the poststack domain due to the varying depth of the seabottom in the Arabian Gulf.

Point-source/point-receiver solution for reservoir characterization: a case study (IPTC 10570)

Anderson, J., P. van Baaren, A. Smart and A. Shabrawi (WesternGeco); A. El-Emam and G. Rached (Kuwait Oil Co.)

A major resource holder (MRH) and a major integrated service provider conducted the first point-source/point-receiver (single-sensor) onshore seismic survey in the Middle East in early 2004 as a pilot study under a Joint Technology Agreement. The study investigated and subsequently determined that single-sensor acquisition and processing techniques could improve seismic imaging and reservoir characterization of the onshore Minagish field, for which previous attempts to derive reservoir properties from seismic data had been largely unsuccessful. The key to success was the ability of single sensor acquisition and processing technology to effectively remove noise (Ozbek, 2000) and preserve signal fidelity and high frequencies in the prestack data.

Shot-domain data reconstruction and its application to suppression of 3-D surface-related multiples (IPTC 10585)

Baumstein, A., M.T. Hadidi and D.L. Hinkley (ExxonMobil)

We present a DMO-based technique for reconstruction of densely and regularly sampled shot records from conventional marine data. The reconstruction process allows us to overcome aliasing that typically affects marine data in the cross-line direction and enables us to apply high-end processing techniques, such as 3-D SRME, to conventional marine data without imposing additional acquisition requirements. A low-cost version of our reconstruction method, which is particularly suitable for use as a part of a multiple-suppression processing flow, is introduced and its advantages and limitations discussed. An example of performing data reconstruction for a conventional marine field dataset, followed by application of 3-D SRME, is presented. This field data example is used to illustrate how the choice of data reconstruction method impacts the quality of multiple suppression.

3-D anisotropic depth migration for VTI media: theory and case histories (IPTC 10481)

Bienati, N., C. Andreoletti, A.M. Melis, P. Cibin, L. Pizzaferri and D. Calcagni (Eni)

Prestack depth migration algorithms are based on approximate models of elastic wave propagation in the subsurface. One of such approximations consists of the assumption that the earth response is isotropic. In fact, in some areas it has been observed that the depth of reflectors determined from surface seismic data are often deeper than well log depths. These misties have been correlated with the presence of VTI anisotropy due to shales. Moreover, it is a common experience that VTI anisotropy induces lateral mispositioning and defocusing in conventional isotropic depth migration. These limitations can be overcome by taking VTI anisotropy into account during migration. This paper discusses the VTI extension of a proprietary Isotropic 3-D Prestack Kirchhoff Depth Migration algorithm. This extension impacts mainly the ray-tracing algorithm underlying Kirchhoff migration. The anisotropic ray tracer exploits a parsimonious acoustic approximation of VTI anisotropy such that only P-wave traveltimes are computed. This approximation is reasonable for weak anisotropy since in this case mode conversions are negligible. Comparisons are shown from isotropic and anisotropic depth migrations results, for both synthetic and field data, showing the improvements gained by taking anisotropy into account.

CRS seismic processing: a new approach to obtain high-resolution images from sparse 3-D-exploration surveys (IPTC 10535)

Coman, R., G. Gierse and H. Trappe (TEEC); S. Robinson and M. Owens (Anadarko), and E.M. Nielsen (Maersk)

The CRS method assumes subsurface reflector elements with dip and curvature. The corresponding CRS stacking operator is not limited to a single CMP gather, but collects the reflection energy of a subsurface element from all contributing traces, including neighbor CMPs of the imaging location. CRS imaging of the sparse 3-D data provided a strong increase in subsurface resolution, and signal-to-noise ratio. It also resolved the faulting which was largely buried in noise in conventional images. The combination of sparse 3-D aquisition with CRS processing proved to be a suitable strategy for achieving good subsurface resolution at limited costs.

Global offset seismic and electromagnetic methods for improving seismic imaging (IPTC 10375)
Dell'Aversana, P. (Eni)

In the last decade a new acquisition scheme called "global offset" has been tested and successfully applied for optimizing seismic imaging. It allows the recording of high-fold seismic data with a wide range of offsets with limited additional costs. The first advantage is the possibility to record a redundant data set that can be used for stable tomographic inversions. Moreover, highly energetic wide-angle reflections can be included in the prestack depth migration process. In this paper we show, using real cases, how tomography and prestack depth migration of global offset data can help in solving critical problems of the time-depth processing, improving seismic imaging and interpretation.

Finally we discuss the importance of including also DC (direct current) and electromagnetic (EM) methods for improving the velocity fields when seismic is not sufficient for an appropriate imaging. The key idea is that non seismic applications, such as continuous profiling magneto-telluric and geo-electric methods, can be complementary to seismic. During the last ten years we optimized the techniques for acquiring and processing simultaneously seismic, DC and EM data in the appropriate way in order to integrate them quantitatively. This integration is performed through joint and/or cooperative inversion. Real cases of this approach are discussed.

Challenges in seismic data acquisition and processing-the Petronas experience (IPTC 10656)
Low, C.F. and D.P. Ghosh (Petronas)

Petronas has been actively acquiring large volumes of seismic data in varied and difficult terrains to support its worldwide exploration, development and production activities. In the Malay Basin of Malaysia, the challenge begins with imaging complex stratigraphic reservoirs that are often below conventional seismic resolution. The Malay Basin, being a fairly matured exploration and production province also poses another challenge, i.e. acquiring high-quality seismic data around platforms and other obstructions. In Vietnam, our team was tasked with imaging complex fractured basement reservoirs under an overburden of clastic and volcanic rocks. In Indonesia, obtaining high-quality, contiguous data over a land-marine interface required four different acquisition techniques and special processing workflows. In offshore Mozambique, East Africa where strong currents prevail in a N-S direction, binning and stacking methodology was used to ensure a thorough reflection of the subsurface. The high-elevation changes in the mountainous region of Yemen called for a special array design, dual elevation and hybrid static routines, while under the dunes of Algeria, the low relief structures needed proper accounting of static variation through modeling.

This paper outlines the various technical challenges faced in the above regions and the solutions that were designed for them. While specific solutions are required in special circumstances, Petronas' underlying objective is to acquire optimal data that will last the life cycle of a field where the surveys form the base cases for eventual reservoir monitoring through 4-D seismics. Imaging through gas clouds, detection of fractures and improving resolution of thin pay sands and seals are some of our continuing challenges. With strong focus on proactive resolution of technical issues, the operational challenge of striking the right balance between quality, cost and efficiency is managed. Health and safety and preservation of the environment during seismic operations remain as an underlying principle of Petronas.

Effect of noise suppression on quality of 2C OBC image (IPTC 10602)
Shatilo, A. and T. Rape (ExxonMobil)

Two-component ocean bottom cable (2C OBC) data are often affected by substantial noise. The noise is probably caused by shear-wave energy registered on the vertical geophone. It exhibits random properties in common-shot domain but coherent properties in common-receiver domain. This phenomenon is observed in most OBC surveys worldwide, and the noise level can be very substantial. Typically, there is a substantial moveout difference between the noise and the signal, i.e. reflected PP waves, allowing use of velocity filtering for noise suppression. Velocity of sound in water can be used as a quite universal parameter for normal moveout (NMO) correction before the velocity filtering. The NMO correction substantially simplifies design of the velocity filter. Efficiency of the proposed approach is illustrated using real 2C OBC data.

Information content in forward 4-D seismic modeling and elastic inversion (IPTC 10660)
Skorstad, A., O. Kolbjornsen (Norwegian Computing Center); A. Drottning, H. Gjoystdal (NORSAR); and O. Huseby (Institute for Energy Technology, Norway)

Elastic seismic inversion is a tool frequently used in analysis of seismic data. Elastic inversion relies on a simplified seismic model, and generally produces 3-D cubes for the compressional and shear wave velocities (Vp and Vs) and density. By applying rock physics theory such volumes may be interpreted in terms of lithology and fluid properties. Understanding the robustness of forward and inverse techniques is important when deciding how much information seismic data really carry. This paper discusses the observed deviation between a reference and simulated reservoir, and its dependency on the seismic parameters and the reservoir characterization parameters.

The ability to utilize the results from a 4-D seismic survey in reservoir characterization will depend on several aspects. To investigate this, a loop that performs independent forward seismic modeling and elastic inversion at two time stages has been established.

The multidisciplinary workflow has several independent steps. (1) Generation of a synthetic reference reservoir, by realistic geostatistical modeling. (2) Flow simulation of the reference reservoir to predict reservoir conditions at survey acquisition times. (3) Establishing a relationship between petrophysical and fluid properties and seismic parameters by a rock physics model. (4) Generation of seismic AVA responses corresponding to reservoir conditions at base and monitor survey times. (5) Elastic seismic inversion of both AVA response sets. (6) Simulation of lithology and fluid parameters conditioned on seismic inversion. (7) Comparison of static reservoir parameters of reference and simulated realization. (8) Comparison of seismic responses at initial and monitor survey times.

By working on a realistic synthetic reservoir, full knowledge of the reservoir characteristics is achieved. This makes the evaluation of the questions regarding the fundamental dependency between the seismic and petrophysical domains stronger. The theoretical limitations of the information content of the seismic data, including 4-D, are investigated since the synthetic reservoir is an ideal case with accuracy never achieved in the applied situation. The production deviation between the reference and predicted reservoir was significantly decreased by using 4-D seismic data in addition to the 3-D inverted elastic parameters.

Linearized Seismic AVO Inversion: a variational Bayesian learning method (IPTC 10263)
Soltani, R. (Laval University)

AVO (amplitude-varying-with-offset) is a seismic prestack inversion technique for estimating elastic parameters of the subsurface. The seismic AVO inversion problem can be formulated as a linearized or nonlinear inverse problem. It is a multidimensional and highly ill-posed inverse problem. It is affected by strong noise and measurement uncertainty. Therefore, in seismic AVO analysis, the goal is not only to find the model that best fits the data, but also to characterize the uncertainty of the analysis. Uncertainty characterization of seismic analysis makes the geophysical interpretation more reliable. The Bayesian formalism generally constitutes a powerful approach for solving many seismic inverse problems. It allows combining available prior knowledge with the information contained in the seismic data. The solution of a Bayesian inverse problem is given by the joint posterior distribution of model parameters. Stochastic approximations of the true posterior are exemplified by the MCMC method and more recently by the *particle filtering* (PF) method. For most seismic inverse problems, stochastic approximation techniques are computationally unappealing. The *maximum a posteriori* (MAP) is the simplest Bayesian method for estimating model parameters. It provides the explanation that maximizes the posterior distribution. The *maximum likelihood* (ML) is a popular non-Bayesian method for estimating model parameters. It provides the explanation that maximizes the likelihood of the data. It assumes that the model parameters are deterministic and omits the pertinent prior knowledge on them. In practice, both MAP and ML point estimators have severe problems with over-fitting the data and model-order estimation. In this paper, the recently-developed variational Bayesian learning is proposed as a new method for solving the linearized seismic AVO inversion problem. Variational Bayesian learning allows the true joint posterior distribution of model parameters to be approximated by a simpler approximating ensemble for which the required inferences are tractable. The main advantage in resorting to variational Bayesian learning is its robustness to the over-fitting problem, which is major in practice. This probabilistic machine-learning method allows finding an optimum balance between the representation power and the model complexity of the data.

Milestones in OBC data processing (IPTC 10637)
Soudani, M.T.A., J.L. Boelle (Total) and P. Ricarte (Institute Français du Pétrole)

Ocean-bottom cable (OBC) technology reveals more and more potentials in PZ imaging. It shows a better image in comparison with the conventional streamer result. In this paper, we will describe the methodology for processing OBC data. We will focus on the key points that could explain the effectiveness of this technology. After a description of OBC data, we will see that many issues are specific to this technology due to the fact that it is half-way from land and marine acquisition. We will show how we deal with different issues such as reorientation, coupling, noise and water-layer multiples attenuation through our new methodology for PZ summation. Receiver ghost elimination, high-fold and wide-azimuth coverage are the main points that differentiate the OBC from the conventional streamer and contribute to the improvement of the results. We will show how these features contribute to the building of a good structural image. Moreover, processing the data with respect to the azimuth is important to fully take into account 3-D heterogeneities and possible azimuthal anisotropy by tracking velocity variations. For that purpose we settled an effective methodology that allows us to check these variations through adequate and accurate QCs. All these topics will be illustrated on several real datasets.

Managing risks in shallow-water 3-D seismic acquisition: a case study in Qatar (IPTC 10377)
Swingholm, E.K. and B.P. Collins (Anadarko)

Acquiring bottom cable 3-D seismic data in environmentally sensitive shallow-water areas greatly increases the need for planning and project management to ensure a safe and efficient program. Addressing these challenges on such a program in offshore Qatar Block 13 demonstrated the value of regular and proactive project team coordination and flexibility; and the skill set and knowledge base of a diverse multidisciplinary team.

RESERVOIR CHARACTERIZATION AND SIMULATION

A mega-cell simulation model of the Shaybah field, Saudi Arabia (IPTC 10240)
Al-Awami, F., K. Hemanthkumar, S. Salamy and R. Sadler (Saudi Aramco)

This paper presents the results of a 4.2-million cell simulation model for the Shaybah field in Saudi Arabia. This model was a follow-up to a previous model that was used to scope the initial development of the field. Since then, many wells were drilled, the facies templates were updated and the relative permeability curves were refined. This model has had a significant impact on optimizing the production strategy of the Shaybah field including designing and locating newly drilled multilateral and smart wells. Reservoir simulation was used extensively during the development stage of the field and is being used continuously to assess different production strategies, and to optimize well placement and completions. Since the field first came on-stream more than seven years ago, a comprehensive data-acquisition program was initiated and a new geological model was built, which in turn led to building a new simulation model. During the process of field development and the simulation update, the importance of several components of the model became more apparent. Such components were the facies templates, the interfacial tension and contact angles and the shape of the relative permeability curves for the various rock types. The impact of improved facies templates resulted in a better permeability model and in turn in a better pressure match; the impact of the gas/oil relative permeability curves refinement was seen in an improvement in the gas-oil ratio match and the impact of the interfacial tension and contact angle resulted in improving the initial water movement.

Optimizing production/injection and accelerating recovery of a mature field through fracture simulation model (IPTC 10433)
Al-Garni, S.A., B. Yuen, N.F. Najjar, S. Lyngra and M.A. Al-Shammari (Saudi Aramco)

Abqaiq field is one of the largest and most mature oil fields in Saudi Arabia. The two producing reservoirs, Arab-D and Hanifa, are both fractured and are separated by the very thick non-reservoir Jubaila Formation. The Arab-D and Hanifa reservoirs are in direct hydraulic communication through faults and fractures. New geologic and simulation models were built for the three formations of interest using Dual Porosity/Dual Permeability (DPDP) formulation and enabling optimization of the field production/injection and acceleration of recovery of this complex system. Detailed fracture characterization was conducted on cores and borehole images. Fracture intensity formulae were developed based on geologic drivers such as structural curvature, porosity, lithology, bed thickness and stylolite density. The generated fracture network was upscaled using a single-phase method to obtain fracture permeability. The final simulation model was developed by up-layering of the 14-million-cell geological matrix model to 2.5 million cells. Simulation of multimillion cell models with the DPDP formulation is now both economical and practical with the utilization of Massive Parallel Processing (MPP) technology.

A workflow was developed to model the two fractured reservoirs with inter-reservoir communication through fractured nonreservoir formation using DPDP options. Equivalent Single Porosity/Single Permeability (SPSP) and a hybrid SPSP/DPDP models were also constructed to speed-up the history match process and to gain insight into the reservoir fluid flow. Significant gain of turn-around time was established through the utilization of MPP and SPSP model. The SPSP model runs seven times faster than the DPDP model under MPP. The DPDP model improves history match quality in the Hanifa reservoir and predicts well performances more accurately in this fracture-dominated system. Results of these three multimillion cell models have contributed to the deeper understanding of recovery mechanism leading to improved efficient optimization of production and injection strategies for this complex field.

Use of fuzzy-logic permeability models to facilitate 3-D geocellular modeling and reservoir simulation: impact on business (IPTC 10152)
Amabeoku, M.O., C. Lin, A.A. Khalifa, J. Cole, M. Dahan and J. Jarlow (Saudi Aramco) and A. Ajufo (Petroleum Services)

Permeability is an important reservoir evaluation property and is vital to well-completion strategies, reservoir productivity, 3-D geocellular model construction, and reservoir simulation. Despite its importance, it is still one of the most difficult petrophysical properties to predict accurately. Simple porosity-permeability relationships have been used extensively, even though the relationship between them is admitably poor. The problem is even more complex when conventional open-hole log responses are used to predict permeability in heterogeneous carbonates. Logs are obtained in all wells, whereas only a few wells are cored. Therefore, it becomes obvious that if conventional logs can be used to predict permeability, then continuous permeability traces can be as commonplace as porosity traces in well sets, instead of sparse core data.

This paper describes the use of fuzzy logic to model and predict permeability in cored wells by calibrating core permeability against conventional open-hole logs. Fuzzy logic is an application of recognized statistical techniques. It is an extension of conventional Boolean logic (zeros and ones) that has been developed to handle the concept of "partial truth" and for modeling uncertainties. The permeability models developed were then used to generate permeability trace in each well across the field. In this application, fuzzy logic was preferred to the conventional porosity-permeability regression and neural networks because the results worked best as demonstrated by blind verification to core data and the excellent quality of reservoir simulation results.

There was a very good match between the modeled permeability, the core data, and flow-meter data in cored wells that had flow-meter data. The match was also very good in noncored wells that had pressure build-up data. Having validated the model in these wells with hard data, we proceeded to populate the 3-D geocellular model with the generated permeability traces in all wells. Cokriging the log of permeability with porosity was used to distribute permeability in the 3-D model. This conditioning facilitated consistency between porosity and permeability trends, which agreed very well with observed stratigraphic trends in the reservoir. The correlation of the logarithm of permeability to porosity of core (plug) data is very good, with coefficients of 0.65 to 0.75 for different layers in the reservoir. The resulting geological models were used in reservoir simulation of two complex carbonate reservoirs. Significant success that is attributed to the use of fuzzy-derived permeability was observed during the history matching phase. The permeability was never modified and yet the 55-year production history was matched with high accuracy tolerance, in only two weeks for each of the two reservoirs studied. In addition, water saturation logs were accurately mimicked in the simulation model. A reduction of 80% of the project duration was achieved.

A method to simultaneously describe gravity and imbibition in fractured reservoir simulations (IPTC 10941)

Boerrigter, P.M. (Shell)

In densely fractured reservoirs one has to rely on natural mechanisms like capillary imbibition or gravity to recover oil from the matrix reservoir rock. Capillary forces are an efficient displacement mechanism for rocks that are water-wet: these rocks prefer to hold water over oil and, once exposed to water via the fracture system, strongly absorb water thereby expelling oil to the fracture system, from where it can be produced. The alternative situation, where the rock prefers to hold on to oil, also exists (oil-wet or mixed wet rock). In such cases, the most effective way to produce oil, is to rely on gravity. By depletion or via gas injection, a gas cap can be formed in the fractures system. This gas surrounds the oil in the tight matrix rock and, because gas has a lower density than oil, the oil will start to drain from matrix stacks into the fracture system due to gravity. In actual field cases, usually both gravity and some degree of imbibition contribute.

The standard approach in fractured-reservoir simulators is to describe fractures and matrix rock as separate systems that can interact with each other (the dual continuum approach), where interaction between matrix and fracture system is governed by shape factors. A proper description of Gas-Oil-Gravity-Drive (GOGD) processes in reservoir simulators is complicated by the nature of gravity to act only vertically and not in all directions as is the case for imbibition and depletion. This paper describes an extension of the dual continuum methods that allows a simultaneous accurate description of gravity and imbibition processes. A comparison is made with methods proposed in the literature and available in commercial simulators. The method has been successfully applied to study fractured reservoirs where gravity and imbibition effects both contribute.

Assessment of interwell communication in the carbonate Al Khalij oilfield using isotope ratio water sample analysis (IPTC 10628)

Danquigny, J., J. Matthews (Total); R. Noman (Qatar Petroleum) and A.J. Mohsen (Total)

Assessment of communication between water injectors and oil producers is a key issue to implement improved oil-recovery programs. This paper presents an innovative use of isotope ratio water sample analysis to characterize injector-producer communication and intrareservoir connectivity in a mature field. Salt analysis is the standard approach to differentiate injection water from formation water, and assess water injection sweeping efficiency. This requires the brines to have different compositions. However, interactions from the mixing of the two waters or with the formation can prevent reliable information from being obtained from such analyses. The isotope ratios of water samples are not sensitive to these interactions. This technique is often used in exploration to assess inter-reservoir connectivity at the delineation stage. This paper shows the successful application of isotope ratio analysis to the complex Mishrif carbonate reservoir of the mature Al Khalij field located in offshore Qatar. The field has been in production since 1997 and water is injected from a shallow aquifer, while coning from a bottom aquifer is suspected. In this field, Strontium, Oxygen and Deuterium isotope ratio measurements were carried out on samples collected from a number of wells across the field. This technique enabled us to assess the percentage of injection water produced at each well, and assist in optimizing water injection management.

Fracture network modeling and dual-permeability simulation of carbonate reservoirs (IPTC 10954)

DeGraff, J.M., M.E. Meurer, L.H. Landis and S. Lyons (ExxonMobil)

Fractured and fracture-enhanced reservoirs are becoming increasingly important as the world's remaining hydrocarbon assets are developed. New modeling and simulation techniques must be developed to guide business decisions, improve economic forecasts, and maximize productivity. To address this need, a fractured reservoir modeling and simulation workflow was developed to integrate evolving technology for fracture characterization, geologic modeling, and flow simulation. The workflow is based on: (1) common-scale geologic and simulation models; (2) fine-scale element models to compute effective matrix permeability; (3) analysis of fracture data from core, image logs, and outcrop; and (4) integration of field performance, structure, stratigraphy, and lithology. Directional equivalent fracture permeability, porosity, and matrix block dimensions are estimated using discrete fracture network (DFN) and 3-D geologic models, while effective matrix permeability is derived using proprietary technology (patent pending). Fracture analysis consists of identifying structural and stratigraphic controls on fracture data from available sources, and then using this knowledge to derive a set of rules to populate a DFN model. Dual-porosity/permeability reservoir simulation models are built in EM^{PowerTM} using similar grid geometry and cell size, effective matrix properties, and DFN-generated fracture properties. Simulation results show a better history match with less iteration than previous models when compared with multiphase production history. In our test cases, dual-porosity/permeability models more accurately capture the impact of fractures on fluid flow than do single-medium models. Our study also demonstrates an effective and efficient process for dual-porosity/permeability modeling and simulation of fractured reservoirs.

Geomechanical modeling of a pore collapsing carbonate: compaction and subsidence of a field in Oman (IPTC 10680)

Dudley, J.W., A. van der Linden (Shell) and G.F. Mueller (Petroleum Development Oman)

A field in Oman provides a good example of compaction and subsidence due to a pore-collapsing carbonate formation. The field is comprised of a gas reservoir in the Natih Formation and an oil reservoir in the deeper Shu'aiba Formation. Both reservoirs are formed by high-porosity carbonates that can display a highly compressible "pore collapse" response with depletion. Both reservoirs are in production. Gas production from the Natih reservoir started in the early 1970s, and continues at present from a dozen wells producing from the center of the field. Oil production from the underlying Shu'aiba reservoir began in the late 1960s, and the field has been under waterflood since the early 1970s. All 450+ Shu'aiba producers/injectors are drilled through the compacting Natih reservoir. Compaction damage to these oil wells is a major incentive for understanding the compaction and subsidence in this field.

This paper presents the results of a detailed geomechanical study to predict subsidence and compaction for the field. Core, log and field data are all incorporated to create a calibrated 3-D geomechanical model for predicting ongoing field subsidence and estimating compaction potential. Key to this is an understanding of the field geology and diagenetic controls on rock strength and compaction in the Natih reservoir. Core compaction tests show the reservoirs are highly compressible, pore-collapsing carbonate formations. Although this is a highly non-linear compaction behavior, *insitu* field compaction measurements show an averaged, more linear response. This fact advocates against using a 'pore collapse trend' to predict *insitu* compaction. The measured field subsidence in the late 1990s and early 2000s is successfully predicted assuming an average linear material response, provided the variable diagenetic character of the field is honored for the pore-collapsing facies. Extrapolation of the model indicates compaction strains at the end of field life in the order of 5% in the crest of the field and a maximum subsidence of about 2 meters.

Experiences using EQR modeling for saturation predictions in a Middle East carbonate reservoir (IPTC 10878)

Engtrom, F. and J.C. Toft (Maersk)

The EQR (Equivalent Radius) method was developed as a "saturation-height" model for the North Sea Chalk in the early 1990s, but experience with the application of the EQR model has demonstrated that it is a general model applicable to any type of reservoir. The objective for the development of the EQR model was to allow an accurate modeling of the long capillary transition zones in chalk, and to extract the areal variations in the free water level (FWL) caused by hydrodynamic and geodynamic effects. The EQR method includes a preliminary calibration of the "saturation-height" model by core data and an iterative procedure involving forward and reverse modeling of the logged saturation and porosity data from individual wells. The iterative procedure allows an improved calibration of the "saturation-height" model, an improved calibration of the log analysis models, extraction of the depth of FWLs at the vertical well locations and along horizontal wells, inference of the presence/absence of capillary pressure barriers and inference of the state of the hydrocarbon system (e.g. active drainage or active imbibition).

Data from the EQR modeling of the individual wells in a field can be applied to map the areal variations in the controlling FWLs and provide data on the controlling mechanisms for the hydrocarbon distribution outside well control. This allows a much more accurate prediction of the hydrocarbon distribution outside well control and therefore a more accurate prediction of hydrocarbon-initially-in-place. These two features have proven very helpful in the analysis of the large low-permeability carbonate reservoirs in the North Sea and Middle East areas. This paper describes the background and basic principles behind the EQR-modeling concept and how it has been used to unravel the complex fluid distribution in the Kharaib limestones (Al Shaheen field, Block 5, Qatar).

Reservoir characterization in upper Khuff reservoirs and its importance in field optimization (IPTC 11043)
lnsalaco, E., E. Cassou, E. Derbez, O.-P. Hansen, C. Legorjus, C.J. Fraisse and C. Javaux (Total)

The Khuff Formation is a major reservoir in Qatar and the rest of the Middle East Gulf region, and contains some of the world's greatest gas reserves. Geologically, the carbonate platform system is complex with fine-scale heterogeneities which impact the static and dynamic reservoir characteristics. These heterogeneities are depositional, stratigraphic and diagenetic in nature and therefore reservoir characterization needs to be an integrated multidisciplinary and multiscale approach. In order to address these issues a large multidisciplinary and multiscale subsurface study has been launched on a large database including fields from across the region. The aim is to better understand the facies distributions, sequence stratigraphic architecture and the regional reservoir development, in order to better characterize dynamically reservoir behavior.

Geologically-based fine-scale reservoir characterization is needed in all field optimization projects and this starts at the appraisal phase of field evaluations, and not just in mature field scenarios. This necessitates an "anticipation" of the kind of field optimization issues that will be eventually needed. It is also important to think of geological reservoir characterization in dynamic terms at the earliest stage possible, but this must always be underpinned by a strong geological framework. This is achieved by calibration of various dynamic data (well tests, production profiles and well interference tests) with geological understanding, particularly sedimentological and diagenetic reservoir characterization.

The static reservoir model in Khuff reservoirs is highly dependent on the precise type of sedimentary facies, the stratigraphic context and the type of diagenetic overprint, since these control the fine-scale heterogeneity. However, the dynamic reservoir heterogeneity (characterized by the dynamic data available) is particularly sensitive to the diagenetic overprint (i.e. the development of dolomite in grain-supported facies), and it is seen that the fine-scale permeability modeling and 3-D permeability architecture is highly diagenetically influenced and fundamental to understanding the dynamic behavior of the field. Moreover the understanding of the 3-D permeability architecture (particularly the high permeability zones around the dolomite-limestone transitions) is important for the application of stimulation techniques, such as acidification.

The integration of the fine-scale reservoir characterization into the reservoir model is a key step, but governed by the precise objectives of the reservoir model. In particular the resolution of the model must be appropriate to the reservoir model objectives (large-scale pore volume calculations versus fine-scale dynamic sensitivity to geological heterogeneity, and adapted if necessary). In-house reservoir-scale modeling tools have been used to model the fine-scale reservoir heterogeneity, and create multiple realizations of the static reservoir properties. Finally these are modeled dynamically to assess the impact of the geological parameters on the production profiles.

Applications of sequence stratigraphy and geological modeling to mature field development: Khalda Ridge, Western Desert, Egypt (IPTC 10137)
Mahgoub, I.S., K. Mowafi, H. Hussein and F. Wehr (Apache)

A joint study integrating geological and engineering data was undertaken to locate infill wells and to optimize the injection pattern in Hayat-Yasser, Kenz and Salam fields in the western desert of Egypt. The focus of this work was the Cretaceous Bahariya and Abu Roash "G" formations, which are sedimentologically described as estuarine to shallow-marine sandstones deposited in a mixed clastic-carbonate ramp setting. All major seismic surfaces were remapped using prestack time-migrated data. A detailed sequence-stratigraphic framework based on core description and petrophysical analysis provides the static reservoir framework. These geologic data are incorporated in a detailed 3-D geological model, which forms the basis for all structural and reservoir mapping. Pressure and production data were analyzed within this framework, in order to identify potential infill and recompletion opportunities as well as potential improvements in changing water-flood pattern from peripheral to internal and to dedicated injection.

Analysis of core and thin sections to determine the history and characterictics of fractures and stylolites (IPTC 10317)
Mann, A., C. O'reilly and D.C.P Peacock (Fugro Robertson)

Determination of the nature and distribution of fractures and stylolites in reservoir rocks requires careful analysis of core, and correlation of fracture and stylolite frequencies with geological drivers. Traditional geological skills are required to interpret the data and to enable a field to be populated with fractures and stylolite in a reservoir model. The relative timing of events plays a crucial role in determining the nature of fractures. For example, open fractures and faults formed at the same time, but clustering does not occur if the open fractures predate or post-date the fautls.

Improved characterization and modeling of capillary transition zones in carbonate reservoirs (IPTC 10238)
Masalmeh, S.K., I. Abu-Shiekah and X.D. Jing (Shell)

Oil-water capillary transition zone often contains a sizable portion of a field's initial oil-in-place, especially for those carbonate reservoirs with low matrix permeability. The field development plan and ultimate recovery may be significantly influenced by how much oil can be recovered from the transition zone. This, in turn, depends on a number of geological and petrophysical properties that influence the distribution of initial oil saturation against depth, and on the rock and fluid interactions that control the residual oil saturation, capillary pressure and relative permeability characteristics as a function of initial oil saturation. Due to the general lack of relevant experimental data and insufficient physical understanding of the characteristics of the transition zone, modeling both the static and dynamic properties of carbonate fields with large transition zones remains an ongoing challenge. In this paper, we first review the transition zone definition and the current limitations in modeling transition zones. We describe the methodology recently developed, based on extensive experimental measurements, for modeling both static and dynamic properties in capillary transition zones. We then address how to calculate initial oil saturation distribution in the carbonate fields by reconciling log and core data and taking into account the effect of reservoir wettability and its impact on petrophysical interpretations. The effects of relative permeability and imbibition capillary pressure curves on oil recovery in heterogeneous reservoirs with large transition zones are assessed. It is shown that a proper description of relative permeability and capillary pressure curves including hysteresis, based on experimental special core analysis data, has significant impact on the field performance predictions especially for heterogeneous reservoirs with transition zones.

Quantitative and statistical approach for a new rock- and log-typing model: example of Upper Thamama Formation, onshore Abu Dhabi (IPTC 10273)

Rebelle, M., M. Al-Neaimi, M.T. Ribeiro (ADCO); S. Gottlib-Zeh, B. Valsardieu and B. Moss (Techsia)

A new rock-typing approach has been applied to a Lower Kharaib reservoir from an in-development field of onshore United Arab Emirates. A high-resolution sequence stratigraphic framework introduces five *high-frequency sequences* (HFS) which control the final layering of the model. Transgressive and prograding intervals display different lithofacies and will have to be considered separately. Discrimination of the model in half-sequences allows the construction of facies-proportion curves within each half-sequence. Use of these proportions in the geological model will allow uncertainty assessment. The rock-typing approach has been completed following a workflow supported by a dedicated software (TECHLOGTM). A statistical and purely objective method was applied, leading to a quantification of the uncertainty on the relationship between geology (lithofacies) and *petrophysical groups at core scale* (PGc). Each lithofacies is in fact a combination of different petrophysical properties.

An important phase of data quality control on logs (including normalization) enabled to obtain homogeneous log data and to discard inconsistent data. The facies log-typing used neural network supervised by the core facies. Around 75% prediction success was attained when comparing observed against predicted facies outside the reference data set and almost 85% successful prediction obtained within the training set. The petrophysical groups or RRT assignment has been determined from both core and log data based on log-derived predictions of porosity and permeability. These petrophysical groups have been quantitatively defined incorporating the capillary pressure data with the routine core data at core scale, and using supervised neural networks derived for the log scale and consequently in non-cored wells.

Finally, taking into account the uncertainties from this study (lithofacies proportion per half-sequence, quantitative relationship between lithofacies and PGc and/or PGL), an uncertainty analysis could be done at the level of the geological model by producing multiscenario models. This paper outlines the methodology used and the sedimentological aspects of the reservoir. The results for the 21 wells will be used to construct the geological model in a second phase of the reservoir characterization study.

Evaluating gas-injection performance in fractured reservoirs using discrete fracture network models (IPTC 10631)

Sahni, A. (Chevron); R. Bakenov (Tengizchevroli); D. Kaveh, W. Narr and D. Dull (Chevron)

This paper presents an alternative approach to modeling gas injection performance in naturally fractured reservoirs. The two conventional methods of modeling fractures have been to either use a single porosity medium with enhanced tensor permeability or a dual porosity system, where the matrix feeds the higher permeability fracture network. The former approach captures variability in well productivity, which is important during primary production but may not be suitable for modeling displacement mechanisms at the large simulation grid block scale. The dual porosity approach may provide some more flexibility in accounting for displacement mechanisms (imbibition, drainage, gravity effects, etc.), however, calibrating dual porosity models (using an appropriate matrix to fracture transfer coefficient) may again be difficult. We discuss an alternative methodology for generating, simulating and evaluating displacement performance using Discrete Fracture Network (DFN) models. While computationally expensive, the DFN models for smaller sectors could be used to calibrate displacement performance of full field dual or single porosity models. We generated stochastic realizations of fracture patterns conditioned to available data on fracture spacing and orientation using a multipoint statistics approach. These stochastic realizations were used to investigate the impact of fracture characteristics on displacement behavior. Fractures were explicitly treated as discrete entities having extremely low pore volume and high transmissibility. The rock-fabric permeability realizations were generated using sequential gaussian simulation, honoring well log data.

The models used to demonstrate the DFN approach were 1,500 x 1,500 m spatially, with thickness varying from 200–400 m. They comprised of one up-dip gas injector and two down-dip producers. Simulations with the DFN approach show the injected gas moving rapidly through the fracture network, with significant bypassing of oil. The effective permeability and dual porosity models on the other hand, displayed more stable gravity-drainage behavior. Displacement characteristics observed from the DFN sector models were then used to calibrate full field dual porosity models. Simulations showed that with higher rock fabric permeability, the displacement efficiency was significantly improved. Sensitivity studies were conducted to investigate the impact of fracture spacing, rock fabric permeability and well intervention techniques on recovery using the DFN approach.

Reservoir surveillance and smart fields (IPTC 11039)
Potters, H. and P. Kapteijn (Shell)

One of the chief challenges facing the industry is to increase the recovery of hydrocarbons from the existing asset base. With access to new resources getting more difficult and production declines facing several major mature provinces, the awareness that we need to manage our assets differently is growing. Recovery optimization is therefore a growing issue with significant future capital, technological and workforce competence development implications. One of the approaches to address the challenge is the "Smart Field" ("digital oil field") concept, introducing advanced system engineering and optimization concepts to asset management. This includes new IT-enabled ways of collaborative working and tight integration of surface and subsurface technologies. In this paper we will focus on novel approaches and technology for detecting and monitoring subsurface changes, an area often referred to as reservoir surveillance or reservoir monitoring. On the basis of examples we will argue that a paradigm shift in reservoir management is called for to ensure optimal field development.

Accelerated understanding and modeling of a complex fractured heavy-oil reservoir, Oman, using a new 3-D fracture-modeling tool (IPTC 10095)
Rawnsley, K., F. Hadhrami, A. Kok, R. Moosa, P. Swaby, S. Dhahab, S. Bettembourg, G. Engen and P. Richard (Petroleum Development Oman); M. de Keijzer (Shell); R. Penney (Petroleum Development Oman); P. Boerrigter, D. Pribnow, M. Koning and H. Hillgartner (Shell)

An intensely fractured reservoir in central Oman is being developed by injecting steam into the crest of the field, heating the oil in the matrix and producing it via a Gas-Oil-Gravity-Drainage (GOGD) process. Both the static and the dynamic data support a strongly fractured (and leached) reservoir. Building 3-D full-field fracture models that capture the possible scenarios proved to be a challenge, largely because to date: (1) most wells in the crest are vertical; (2) a limited number of horizontal wells have been drilled on the flanks; (3) seismic quality is relatively poor; and (4) dynamic constraints on the permeability structure are limited, especially on the flanks. A new 3-D fracture software tool (SVS) has been used to maximize the value of fracture-related reservoir data through improved integration, visualization, analysis and correlation. Rapid interactive analysis of the data set allows the user to efficiently characterize and understand the nature of the fracture system and its relationships to other reservoir parameters. The data analysis indicates that two end member fracture system scenarios could be present in the reservoir: (1) a mechanical stratigraphy related; and (2) fault/corridor related fracture system. This is particularly true of the flank wells, which despite being mostly located away from the main seismic-scale faults on the crest, have evidence for fault-related fracture clusters at intervals down the well bore. For these end member, and intermediate scenarios, "Low", "Medium" and "High" case models were created using fracture trend maps/grids that combine the data and a range of geological constraints. More remote information was included from outcrop fault patterns in northern Oman. A combination of detailed process based discrete fracture generation and rapid fracture attribute generation was used to populate over 15 full-field simulation grids capturing the range of remaining uncertainty of the fracture system across the field.

Integrated fracture characterization and modeling in PDO carbonate fields using novel modeling software and sandbox models (IPTC 10428)
Richard, P. (Petroleum Development Oman); K. Rawnsley P. Swaby (Shell) and C. Richard (Ipedex)

A large proportion of Petroleum Development Oman's (PDO) future production resides in fractured reservoirs. In order to support the development of these volumes, a strong element of fracture characterization and modeling has been included within a number of subsurface studies. The key enabler for these studies is the software technology, SVS (Simple Visualisation Software), developed by the Carbonate Development Team (CDT), in Shell EP-Research. PDO has not only taken a lead role in software implementation but is also steering the ongoing development of SVS according to the needs of active field studies. Currently, SVS is applied to the three themes of Oman's fractured reservoirs: (1) slightly fractured containing light oil; (2) medium/highly fractured containing light oil; and (3) highly fractured containing medium-heavy oil. The key pillar of the SVS workflow is a detailed fracture characterization that leads to the elaboration of a series of conceptual models that capture the range of the subsurface uncertainties. Once the conceptual models have been developed, these can be transformed into discrete fracture models with attached attributes (such as permeability anisotropy, fracture spacing, etc). These models maybe transformed into reservoir simulation properties as per study requirements. The main objective of this complementary paper to Rawnsley et al. (2004) is to illustrate the SVS workflow with particular emphasis on the borehole image analysis and the use of a web-based sandbox model database, to help constrain the fault geometries and the structural understanding of the fields.

Managed induced fracturing improves waterflood performance in South Oman (IPTC 10843)
Saeby, J., (Petroleum Development Oman); H.P. Bjorndal and P. van den Hoek (Shell)

Novel modeling technologies that includes induced fractures in a dynamic reservoir simulator have been used to analyze subsurface aspects of an inverted 5-spot injection pilot. The techniques have allowed an accurate depiction of growing induced fractures. Simulation results indicate that induced fracture growth is limited at injection rates of less than 200 m^3/day but that higher injection rates will result in fracture propagation and a risk of rapid water breakthrough. The results have been validated by field observations. A controlled and cautious increase in injection rate has resulted in a positive production response with rate increases of 50–100% in three of the four producers in the pilot. Results from the pilot have increased the current reservoir understanding and reduced subsurface uncertainties. The knowledge gained is being included in an updated Field Development Plan that will be issued in 2005. The plan will incorporate an optimized injection strategy by a careful and controlled ramp up in injection rate. This project has also advanced induced fracture research with a field verification of the predictive capabilities of the modeling technology.

How to incorporate emerging subsurface information into a front-end design: a green field miscible gasflood example from the southern part of Oman (IPTC 10460)
Soek, H. (Petroleum Development Oman) and A. Vincent (Shell)

The business drive is to deliver projects as fast as possible in a prudent manner. Acceleration needs to be balanced against the risk of a suboptimal development. Parallel working on appraisal and project definition is one answer. This article describes some subsurface-surface interface processes used to accomplish this acceleration successfully. The development consists of a number of non-conventional fields characterized by deep, often geopressured carbonates encased in salt and charged with light but sour hydrocarbons. On primary depletion these reservoirs would only recover a limited amount. Under a miscible gas flood with the right enrichment agents and pressures, the recovery can be significantly improved.

Low-flood-rate residual saturations in carbonate rocks (IPTC 10470)
Tie, H. and N.R. Morrow (University of Wyoming)

Carbonate reservoirs commonly exhibit great morphological complexity from pore to field scale. Interpretation of laboratory waterfloods is often problematic because of unexpected sensitivity of oil recovery to flood rates comparable to field values. The circumstances under which rate sensitivity occurs need to be further identified. In this work, three outcrop limestones with distinct differences in petrophysical properties were selected for investigation of the combined effect of pore structure and wettability on residual saturations. The rocks were tested at very strongly water-wet conditions followed by preparation of mixed-wet states. A comparative study of waterflood recovery was made for mixed wettability with crude oil or mineral oil as the test oil. Mineral oil was tested after either direct displacement of crude oil or first displacing crude with an intermediate solvent to avoid surface precipitation of asphaltenes. Flooding rates ranged from below or near-field rates to well above with increase in capillary number achieved by increase in flood rate. Reduction of residual oil saturation with increase in flood rate ranged from slight for a homogeneous grainstone to highly significant for both a heterogeneous grainstone and a boundstone of very high porosity and permeability.

A laboratory study investigating methods for improving oil recovery in carbonates (IPTC 10506)
Webb, K.J. , C.J.J. Black and G. Tjetland (BP)

Previous studies have shown that waterflood recovery is dependent on the composition of injection brine in clastic reservoirs. Some researchers have also shown that oil recovery from carbonates is dependent on the ionic composition of the injection water. These studies have, however, been generated at laboratory conditions, which are not representative of the reservoir, and therefore it is uncertain whether these IOR benefits are applicable to actual reservoir waterflood oil recovery. A reservoir condition core-flood study was therefore performed on core from a North Sea carbonate field (Valhall) to determine whether the recovery benefits seen in reduced condition experiments, were also obtained from full reservoir condition tests, using live crude oil and brine. In these reservoir condition tests, two reservoir core plugs were selected from the same reservoir layer and were similar in reservoir properties so that comparisons could be drawn between the experiments. Samples were prepared to give initial water saturations which were uniformly distributed and volumetrically matched to the height above the oil-water contact of the samples in the reservoirs. The initial water saturation composition was based upon the simulated formation brine composition of the field. The plugs were then aged in live crude oil to restore wettability. Imbibition capillary pressure tests were then performed at full reservoir conditions, with live oil and brine, using the semi dynamic method. The first experiment utilized a simulated formation water and the second test utilized a simulated sea water, respectively, as the displacing water. The resultant data showed that the sea water used in the capillary pressure test modified the wettability of the carbonate system, changing the wettability of the rock to a more water wet state. This was indicated by comparing the saturation change in the spontaneous imbibition phase of the test between simulated formation and sea waters.

Geomechanics analyses of the crestal region of an Omani gas field (IPTC 10231)

von Winterfeld, C. and S. Babajan (Petroleum Development Oman); A. Amer and J.R. Marsden (Schlumberger)

The Miqrat and Barik deep sand reservoirs of the Saih Rawl gas field in Oman are currently undergoing further development, with the addition of high-angle and horizontal wells. The field has already experienced 4–11 MPa depletion, and geomechanics-related problems already encountered include wellbore instabilities, poor hole quality and casing deformation. With a further 15 MPa depletion being anticipated over the remaining field life, and with the need for deviated wells, geomechanics effects will become more pronounced and the associated technical and economic challenges facing the field may increase.

To assist in well planning and field development, and to understand the problems already encountered in the existing vertical wells, mechanical earth models were generated for three well locations in the crestal region of the field. These covered not only the two main sandstone reservoirs (Miqrat and Barik), but also two shaly formations through which high angle drilling might also take place (i.e. Al Bashair shale above the Miqrat, and the Mabrouk shale between the two reservoirs). This integration of data from drilling, openhole logs, core tests, borehole images, formation pressure measurements, leak-off tests and hydraulic fracturing provided a calibrated and consistent description of the *insitu* state of stress, pore pressures and rock mechanics properties. These models were further improved by accounting for cooling effects of the circulating mud when history matching breakouts and instabilities in the existing wells to the *insitu* stresses, and also by accounting for historical depletion in the field. The depletion modeling was performed analytically and also using a numerical simulator performing finite difference coupled reservoir/stress calculations. The two approaches provided very similar estimates of current and expected formation displacements and estimates of stress changes in the reservoir intervals and their adjacent shales. These results were then considered in the analyses of wellbore stability of the future deviated and horizontal wells. This paper describes these geomechanics analyses and modeling of the crestal region of the field, and how these data were used to assess wellbore stability, compaction and deformation that might affect new-drills or existing completions, both at the current level of depletion and over the projected remaining life of the field.

WELL DESIGN, LOGGING, TESTING AND COMPLETION

Applications of petrophysical scale reconciliation to Saudi Arabian reservoirs (IPTC 10726)

Al-Ali, H.A. (Saudi Aramco) and P.F. Worthington (Gaffney, Cline & Associates)

Core data from three fields have been stress-corrected and upscaled so that they become notionally reconciled with wireline well logs along wellbore axes. The upscaling process draws upon logging tool response functions in a way that optimizes the correspondence between the smoothed core porosity data and density or sonic logs. It is demonstrated that there are significant differences between core-derived porosities at the core and log scales. These differences are tool-specific, and they transmit through to the log-derived porosity. Once a scale-reconciled, log-derived porosity has been validated, it can be input to a core-derived porosity-permeability algorithm. Where this transform is based on compatible, upscaled core data, the results are significantly better than those from the conventional approach that is tied back to the core-plug scale. These observations have formed the basis for improved workflows for the petrophysical evaluation of porosity and the subsequent estimation of intergranular permeability. The approach can be readily extended to the evaluation of water saturation where low-invasion coring has taken place.

Intensive data gathering through a waterflood pilot for redevelopment of a giant fractured carbonate field, Oman (IPTC 10794)

Al-Habsi, M. and P. Stoffels (Petroleum Development Oman)

Due to their strong subsurface heterogeneity many Middle Eastern fractured carbonate reservoirs are characterized by significant and wide range of uncertainties. This paper presents a case study of one of the largest and oldest oil fields in Oman. Despite over 35 years of production through various drive mechanisms, there remains an opportunity to realize significant additional value in the field. This paper presents the largest data acquisition program anywhere in Oman that is ongoing in a giant fractured carbonate field to support the planned water flood project there. A total of 28 wells have been drilled on four inverted 5-spot patterns, each containing a central water injection well, four equidistant producers and two dedicated observation wells. Each well is deviated with an S-shaped hole, so that they arch away from the linear pad on surface and end-up vertically in the reservoir building a square with the injector in the middle. All the patterns have been drilled, completed and been put on production. Initial surveillance activities have been already executed and analyzed.

The primary aim of the project is to gather data about water-flood behavior in different reservoir layers in the field by running reservoir analysis logs in the wells, measuring production data and injecting tracers to track the oil and water movements. The plan is to carry out up to 25 logs (EMI, PLT, PNN, Induction) and pressure surveys (BHP, PBU, PFO) per month, in addition to coring the central water injectors. The first pad "Phase-1" started in September 2004, the second pad "Phase-3" in March 2005, whereas the other two pads "Phase 1-2 and Phase 2-3U" came on stream in August 2005.

Towards the end of 2006 the decision based on the pilot data results will be made on whether to extend the waterflood across the whole field. The alternative would be to rely on Gas/Oil Gravity Drainage, which is a lower investment option than water flood, but ultimately would achieve a lower recovery as well. Also combinations of both development options and/or an FOR development have to be evaluated. This paper will highlight the water flood pilot set-up and the early results from this intensive data gathering and analysis for a water flood project.

Application of wireline formation tester (openhole and cased-hole) sampling techniques for estimation of non-hydrocarbon gas content of Khuff Reservoir fluids in the North field, Qatar (IPTC 10622)

Al-Mohsin, A. and S. Tariq (RasGas) and S.A. Haq (Schlumberger)

Qatar's North Field is the largest non-associated gas field in the world. The North field is being developed primarily to supply feedstock gas for a number of LNG (Liquefied Natural Gas) and GTL (Gas-to-Liquid) plants. Accurate determination of the amount of H_2S and CO_2 in the feedstock gas is critical for the proper design of the LNG and GTL plants. Due to long lead time required for the design and the construction of these processing plants, it is necessary to establish the feedstock gas specifications as early as possible during the FEED (Front End Engineering & Design) process. Moreover, once the plant design specifications are set, early estimation of H_2S and CO_2 content of Khuff reservoirs at the development well locations is necessary to design a well-completion scheme to meet the plant design specification for the feedstock gas.

In 2003, RasGas decided to evaluate several sampling techniques for early estimation of the non-hydrocarbon (NHCG) gas content from Khuff reservoirs. After a thorough study of available options for making reliable measurements of H_2S and CO_2 content of reservoir fluids using down hole tools, it was decided to test Wireline Formation Testers (WFT), both open-hole (OH-WFT) and cased-hole (CH-WFT) tools, in an appraisal well as a "proof of concept" of these technologies for estimation of H_2S and CO_2 contents. The results from both OH-WFT and CH-WFT techniques were compared with normal DST surface recombined samples obtained from the same well. In this paper, the following aspects of OH-WFT and CH-WFT sampling techniques for determining H_2S and CO_2 contents are discussed and the results/analysis presented. (1) Optimal tool/sampling bottles/flow line configuration for reducing H_2S scavenging effect. (2) Comparative analysis on a relative basis between OH-WFT and CH-WFT samples, both on-site and in laboratory. (3) Evaluation of OH-WFT, CH-WFT and DST sample compositional results on a relative basis.

Integration of microelectrical and sonic reflection imaging around the borehole: offshore United Arab Emirates (IPTC 11021)

Al Rougha, H.A.B., A. Sultan (Zakum Development Co.); J. Haldorsen, M. Al-Raisi, W. Borland and S. Chakravorty (Schlumberger)

Horizontal wells are commonly used worldwide to improve recovery of petroleum resources. In offshore Abu Dhabi, the carbonate reservoir contains subseismic features such as faulting and fractures that impact production and enhanced recovery. This paper attempts to identify and link fractures and faults observed near the borehole with surface seismic, in order to provide insight into their extent, distribution, characterization and implications on the reservoir production. The study resolved structural interpretation uncertainty in the 3-D seismic, highlighted the variability in the injected water-front advancement, and provided a methodology to link fine scale observation from microelectrical image logs to intermediate sonic measurements and surface seismic.

Conventional sonic logging is similar to refraction seismic experiments carried out on the earth's surface except that, for the sonic, the source is higher frequency and the source receiver distance and receiver spacing is much closer. This allows the sonic to achieve a higher resolution velocity measurement over a shorter interval. Sonic logging waveforms can also be processed for reflection information in a similar way to reflection surface seismic. Its higher frequency source thus allows for much higher resolution reflection information tens of feet away from the well. The structural dip computations from pilot and horizontal image logs were linked with sonic reflections to mark probable fault locations and to construct a geological cross-section, which used to define the different reservoir layers that intersected along the well trajectory. Structural lineaments (faults and fracture zones) within a given reservoir layer were extended away from borehole by utilizing sonic waveforms. Due to small fault displacement (less than 4 meters) the fault was not originally picked on the surface seismic, but overlaying the interpretation on the attributes indicates the possibility of a fault. The results were subsequently validated by injection profile. Mapping these lineaments improved seismic interpretation, which ultimately lead to better well placement and validated existing dynamic data.

Multidisciplinary evaluation of wellbore instability in Shaly Sand Member Khafji Reservoir in Zuluf field, Saudi Arabia (IPTC 10206)

Al-Shebaili, Y.M., A.M. Shebatalhamd, A.A. Ansari and H.H. Abbas (Saudi Aramco)

This paper presents the results from a case study that integrates detailed rock mechanics and swelling tests with information from petrophysical logs and core properties acquired to evaluate, define and predict the instability mechanism in this portion of the Khafji reservoir. To achieve the objectives, 300 feet of preserved core were cut through the problematic shaly sand member using oil-based mud (OBM). In addition, 200 conventional plugs and 28 whole core samples from eleven wells were utilized for the purpose of developing geomechanical and pore fluid models. Both oil-based mud and water-based mud (WBM) filtrate were used for the swelling and triaxial compression tests. The development of a strength and stress profile for the well is the first step in understanding wellbore instability problems. These profiles are generated using rock properties, drilling experience, *insitu* stress regimes and strength measurements on core samples. The results demonstrate that the *insitu* stress in the Khafji reservoir can be characterized, and the critical azimuths of marked instability increase are discernible. Wellbore instability problems can be predicted and averted.

The optimum mud weight windows to drill horizontal wells have been identified using the geomechanical model. Wells oriented parallel and perpendicular to maximum horizontal stress (S_{Hmax}) require minimum mud weight of 80–84 pcf and wells drilled WNW-ESE require mud weight from 80–95 pcf. The swelling test results point toward increased swelling in the presence of the WBM filtrate compared to the OBM filtrate and a decrease in formation compressive strength when in contact with the OBM. It may therefore be prudent to redesign the already "inhibitive" WBM to suit the formation and the clays.

Successful treatments to enhance the performance of horizontal wells drilled near tarmat areas (IPTC 10188)

Al-Umran, M.I., K.A. Al-Dossary and H.A. Nasr-El-Din (Saudi Aramco)

Tarmat zones have been characterized at the base of oil columns in some of Saudi Arabia's carbonate reservoirs. These zones form a barrier, which physically isolates the producing zones and the injected water. As a result of this barrier, the reservoir pressure will decrease, which will require other means to produce these wells. This paper addresses two strategies to overcome potential problems resulting from the tarmat zones. The first strategy was to drill a tunnel well. The tunnel well works as a conduit that connects the high pressure area to the low pressure area through the tar zone of the reservoir. Field data indicated that this well enhanced the production rate of nearby wells and livened two dead wells. The second technique to address the tarmat present in another field was to use peripheral water injection. Water injectors with extended reach (ER) were completed horizontally at the bottom of the producing zones and just above the tarmat zones.

Challenges were faced in drilling these wells in a populated area in northern Saudi Arabia, and being stratified the tarmat was encountered in open-hole sections of these wells. Tar content varies inconsistently around these injectors and more near wellbore and obviously in the tar layer. This limits the injection rate of these injectors initially to as low as 600 BWD at 2,400 psig. The low injectivity is attributed to the damage induced by the drilling mud (water-based mud) and the presence of tar and asphaltene in the injection zone. Acid stimulation treatments of these wells were needed to reach the target injection rate. A tailored acid treatment was designed to address these challengers. This treatment included pumping aromatic solvent, a regular acid, an emulsified acid and a viscoelastic surfactant-based acid for diversion. Because of environmental concerns, high H_2S content, the spent acid was not lifted following the acid treatments. However, the injectivity index of horizontal injectors increased by several folds. The paper describes the efforts of a multidisciplinary team to enhance the performance of these wells by using the latest technologies in drilling, logging, and well treatment.

Solutions to challenges in production logging of horizontal wells using a new tool (IPTC 10248)

Chandran, T. (Kuwait Oil Company); S. Talabani (Baker Atlas); A. Jehad (Baker Atlas); E. Al-Anzi (Kuwait Oil Company); R. Clark Jr. (BP) and J.C. Wells (International Reservoir Technologies)

Production logging in horizontal wells is always challenging compared to vertical wells. These challenges include the physical deployment of the tools, presence of restrictions along the horizontal section that complicates the analysis, the huge volume of data from different tools and modes that should be interpreted, and later to make meaningful interpretation from these analyzed data. The presence of the three-phase fluid flow will further complicate production analysis. On the other hand, changes in the flow pattern laterally over the horizontal section result in uneven increase or decrease in the fluid rates. Other fluids slow down their flow rates in relation to different parameters and hole condition. In order to fully analyze the huge data acquired using different tools, a thorough investigation on the flow patterns and fluid regime is required to quality check the data before processing and interpreting. Once processed, different log data should be separately analyzed and later compared with other available data. Combined analysis show different flow profile over the horizontal section, along with possible geological features. In this presentation, case history from the region is presented and thoroughly discussed. Some intervals are more specifically analyzed and compared to other logs run in order to confirm the outcomes. The analyzed production log data improved the ability of better optimizing well production rates and managing their integrities within the reservoir.

Achieving performance improvement on a new project: drilling the limit (IPTC 10380)
De Meijer, T., J. Halton and A. Vos (Shell)

DTL (Drilling the Limit) is one of the five performance improvement tools based on the Limit methodology used in the Shell Group. This methodology is used to improve performance by working down from a point of perfection based on the current levels of technology, rather than from incremental improvements in today's performance. In late 2003, a Shell Well Engineering project team re-entered Qatar after an absence of 11 years. The project paved the way for a c. US $6 billion Gas-to-Liquids (GTL) plant scheduled to begin production in 2009. Initial operations activities included the drilling of two wells in offshore Block H4/5 with ENSCO as the drilling contractor. The first well was spudded only 4 months after signing of the Heads of Agreement (HOA). This study describes how the DTL methodology was implemented to achieve a successful first well (although not all the new technology worked as we expected), and a second well that we believe was the fastest vertical Khuff well yet drilled in the North field. Our ability to learn between the two wells is an excellent example of limit learning.

Carbonate rock typing using NMR Data: a case study from Al Shaheen field, offshore Qatar (IPTC 10889)
Frank, S. (Maersk); R. Narayanan (Qatar Petroleum); P.M. Hansen (Maersk); D. Allen, (Schlumberger); T. Albrechtsen, H. Steinhardt, M. Raven and E. Fordham (Maersk); E. Bize and D. Rose (Schlumberger)

Complex pore-size distributions encountered in carbonate rocks have a large impact on the fluid flow characteristics of carbonate reservoirs. Consequently, although nuclear magnetic resonance (NMR) has been frequently used for characterization of clastic reservoirs, it has not been widely applied to carbonates. This paper describes a case study from the Shu'aiba carbonate reservoir of the Al Shaheen field, offshore Qatar. Core data from a study well were used to establish an NMR carbonate rock-typing model for permeability estimation. The rock-typing model was verified in the study well with a wireline NMR logging tool. Core analysis included thin-section petrography, NMR surface relaxivity, mercury injection, porosity and permeability measurements. NMIL distributions determined on core were partitioned and linked to pore body size and pore throat size distributions. Several rock types were also defined based on their NMR and petrographic characteristics. To improve permeability prediction in the cored interval of the study well, an NMR-based permeability equation was derived. The core-calibrated NMR carbonate rock typing model was applied to noncored sections of horizontal wells drilled in the Shu'aiba Formation having logging-while-drilling (LWD) NMR data to improve rock typing and permeability estimation, thus, providing valuable input data for reservoir modeling.

Bridging the gap between the earth science and engineering disciplines: the strategy of using acoustics technology to characterize rock mechanical properties for optimal well design-reliability and placement (IPTC 10229)
Goodman, H.E. (Chevron)

Beginning in the early 1990s, Chevron initiated the strategy of developing mechanical earth models from acoustics-dominated, data volumes. The business driver was to link the geology and geophysics disciplines involved with prospect exploration and development, with the engineering disciplines involved in well systems design. This strategy has culminated in Chevron's capability to build Mechanical Earth Models (MEM) from the reservoir to surface, linking earth physical properties, i.e. rheology, to the geology, seismic geophysics and *insitu* stress character of the entire geologic section. MEMs are now being created during early project stages, to provide a phased approach to assess well systems design risk. Well planners now use MEM volumes for bit optimization and performance prediction, wellbore stability, sand prediction, fracture stimulation design, cuttings disposal design and seismic reservoir characterization for by-passed oil. The presentation will introduce acoustics based rock mechanics concepts, describe Chevron's acoustics-based. rock property, prediction technique, and present field application case histories for selected business units world-wide, including deepwater Gulf of Mexico, North Sea, the Arabian Gulf, offshore West Africa and Asia.

Well-test analysis in low-permeability multilateral wells (IPTC 10686)
Gringarten, A.C. (Imperial College); R. Sharma (Occidental) and A.K. Rajvanshi (Qatar Petroleum)

Multilateral horizontal wells are used extensively in a number of reservoirs around the world, and particularly in the Middle East. Development is often based on patterns of multilateral producers and multilateral injectors, and these, combined with complex reservoir geology, create well test pressure behaviors that are usually difficult to interpret. Ideally, well tests should be conducted one individual horizontal branch at a time, and branch rates and producing lengths should be measured in order to decrease the nonuniqueness of the well test interpretations. In practice, this is not often possible and all branches are tested together. Low-permeability reservoirs add to the difficulty, by reducing the information available within the normal duration of a build-up test. Although theoretical solutions for multilateral wells have been published in the oil literature, there are very few actual examples of well tests and even fewer detailed well test analyses. This paper describes the analyses of well tests on several multilateral wells in a low-permeability carbonate reservoir in the Middle East. It is shown how a maximum of useful information can be extracted from the well test data, using combination of techniques and tools, such as time-lapsed derivative analysis, analytical multiwell simulators, and deconvolution. Limitations and uncertainties in the analyses as a function of the data available are also discussed.

Evaluation of wireline tractor performance in various well completions in Saudi Arabia (IPTC 10186)
Hashem, M.K., S.M. Al Dossari (Saudi Aramco); A.R. Marhaba and M. Zeybek (Schlumberger)

The need for a safe and cost-effective conveyance method in horizontal well logging increased with the increase in the number of horizontal wells and their horizontal section length. Coiled tubing was initially used for conveyance, however it has a limited reach and the operations are complicated with some operational risks, demanding logistics and higher cost. The inchworm tractor was tested and evaluated in various horizontal well completions such as cased hole, slotted liner, gravel packed, ESP, open hole, and multilateral wells; with long horizontal sections. The tractor was also tested in open-hole completions where the formation unconfined compressive strength (UCS) varies from 150 to 23,000 psi. Logging wells with soft formations was the most challenging task. The tractor design was modified to be able to initiate and maintain tractor movement in the soft formation. This paper will cover the test results of the inchworm type tractor such as effectiveness of conveyance, quality of logged data, maximum logged horizontal section and cost saving. It will also discuss the limitations of this technology. The screening process of suitable candidates as well as pre job planning will be summarized.

Optimizing maximum-reservoir-contact wells: application to Saudi Arabian reservoirs (IPTC 10395)
Hussain, A., A. Kumar, S.A. Garni and M.A. Shammari (Saudi Aramco)

The objective of multilateral-well technology is to improve well productivity by maximizing reservoir contact, resulting in field development with fewer wells. Long horizontal wells (up to eight kilometers) are drilled, but the greatest opportunity, as well as the greatest technological challenge, lies with Maximum Reservoir Contact (MRC) wells. An MRC well, by definition, is a multilateral horizontal well with more than five kilometers of total contact with the reservoir rock. Planning of these wells requires extensive modeling studies to optimize total length, placement and configuration of branches, and the use of "smart-well" options such as: (1) selective layer/branch shut-off devices; (2) balanced production to limit flow of fluid through a particular branch; (3) crossflow control; and (4) downhole separators to handle high watercuts. This paper describes how these objectives were met and the well design was optimized. In this work, a number of sector models were used to evaluate different MRC completions based on their total production, well placement and design, stage of depletion, pressure interference between laterals, and impact of water encroachment by downhole control. Applying this reservoir simulator to the development of the northern area of the Greater Ghawar field, we were able to accomplish the following: (1) optimize well placement; (2) optimize numbers and lengths of laterals; and (3) evaluate the benefit of "smart" well completions. Detailed modeling of the proposed MRC wells provided a better understanding of reservoir dynamics that will enable Reservoir Management to make faster and informed decisions. Besides this, the study helped us significantly reduce turnaround time for MRC well evaluation.

Numerical investigation of horizontal well performance with selective completion (IPTC 96395)
Kalita, R. and Y. Jalali (Schlumberger)

This study presents a numerical method of determining the sandface completion profile of a horizontal well to achieve a prescribed production objective. A technique is developed to determine the completion profile that maximizes an objective function (e.g. cumulative production) for a given well operating program in a defined reservoir environment. Sandface completion is modeled in terms of a connection factor between the reservoir grid blocks adjacent to the well and wellbore segments. Well performance is evaluated in terms of cumulative production within specified operational constraints (maximum rate, minimum bottomhole pressure). The method uses a finite-difference technique to determine the sensitivity of well performance to changes in the wellbore-reservoir connection profile. The optimum connection profile is determined by a gradient-based technique using the sensitivity coefficients from the finite-difference method. This approach can be used to either plan the sandface completion during the well design stage, or to optimize the completion after drilling based on measure petrophysical and flow properties of the formation. Examples are given in the paper covering both water- and gas-drive problems.

Al Furat Petroleum Company's cluster approach in near field appraisal delivers early results (IPTC 10909)
Lechner, M., G. Holstege and P. van Daele (Shell)

In September 2003, the Syrian Petroleum Company, PetroCanada and Syria Shell finalized a Production Sharing Contract (PSC) resolving a long-standing dispute and allowing the pursuit of Near Field Potential (aka. Deep and Lateral) in the 35 Development License Areas, operated by Al Furat Petroleum Company (AFPC). The PSC included a commitment to drill 10 appraisal wells, of which one has to reach 5 km total vertical depth subsea. For some 10 years, no work had been done on maturing the Near Field potential of AFPC's fields. The expectation of the remaining potential, based on limited study only, ranged from less than 50 million barrels to more than 250 million barrels reserves. AFPC was tasked with executing the Deep and Lateral activities on behalf of the three shareholders, and the following three targets were set. Firstly, contribute some 8,000 barrels/day year average to AFPC's production to partly offset declining production from the more mature assets. Secondly, identify and mature new reserves for AFPC's resource base. Thirdly, provide an assessment of the remaining acreage potential, including the deep, undrilled reservoirs. In order to achieve these objectives in the fragmented near-field acreage, a Cluster Approach was adopted with the aim to quickly review the potential in the "established Cretaceous and Triassic play" and deliver up to eight drillable prospects/opportunities in 2004.

Use of advanced reservoir data collection and interpretation techniques (IPTC 10893)
Pedersen, M.H. (Maersk), R. Noman (Qatar Petroleum); S. Frank and H.B. Ohrt (Maersk)

This paper presents three examples of reservoir data collection under challenging operational conditions in carbonate and sandstone reservoirs in the Al Shaheen field, offshore Qatar. The examples demonstrate how *Formation Pressure Testing* and *Fluid Sampling* can provide early and often decisive information for field development. Logging operations in the Al Shaheen field are often performed in wells with horizontal sections in excess of 20,000 feet in thin, unconsolidated sandstone reservoirs. To accommodate these conditions, which are far outside the normal operating envelope of the logging tools, new procedures and techniques have been developed to address 'extended reach logging' and to mitigate potential problems with unconsolidated sand. These procedures and techniques are discussed along with the three field cases. The first field case describes how *insitu* hydrocarbon mobility was determined, and how it justified immediate continuation of an appraisal program. The second field case explains how a fluid contact in a very thin sand was confirmed by fluid sampling, and how it eliminated the need for a horizontal sidetrack. The third field case describes how determination of *insitu* fluid properties improved saturation modeling and allowed real-time optimization of the data collection program.

PRODUCTION FORECASTING AND CASE STUDY

Overview of North Field development, Qatar (IPTC 11048)
Al-Kaabi, S.S.S.J. (Qatar Petroleum)

The largest non-associated gas field in the world lies off the northeast coast of Qatar. The North Field contains reserves in excess of 900 trillion cubic feet of gas (TCF) and covers an area of approximately 6,000 square kilometers. The field was discovered in 1971 and an initial drilling program ending in 1995 delineated the approximate size of the structure. The first development drilling project of 15 wells was initiated in 1987, with first production occurring in 1991. Today there are four producing platforms and six LNG trains being operated by Qatar Petroleum, Qatargas, and RasGas. Plans are in-place to more than double the number of platforms by 2010. Current daily production is approximately 4.3 billion cubic feet of gas (BCF) per day with 160,000 stock tank barrels (STB) per day of condensate. Projected rates for 2010 are 18 BCF per day with 610,000 STB per day condensate.

As drilling has been ramping-up so has the understanding of field. Reserve estimates of the early nineties were 273 TCF. Subsequent drilling and more precise modeling have led to current estimates, which show the North Field to contain more than 900 TCF plus 23 billion STB of condensate. The application of new technologies and rigorous application of existing technologies are helping us unravel the intricacies of the North Field, and ensure optimal and economic development of this resource. The fruition of the planning and development work currently underway will see Qatar emerge as the GTL capital of the world and the world's largest producer of LNG.

Reservoir modeling for redevelopment of a giant fractured carbonate field, Oman: experimental design for uncertainty management and production forecasting (IPTC 10537)
Al Salhi, M.S., M.F. Van Rijen, Z.A. Alias and F. Visser (Petroleum Development Oman); H. Dijk, H.M. Lee, R.H. Timmerman, A.A. Upadhyaya and L. Wei (Shell)

Many Middle Eastern fractured carbonate reservoirs, due to their strong subsurface heterogeneity, are characterized by a significant and wide range of uncertainties. During brown-field redevelopment of such reservoirs, producing reliable production forecasts, which incorporate the full range of subsurface uncertainty in a systematic and geologically realistic manner, is a major challenge and a cumbersome task. This paper presents a case study of one of the largest and oldest oil fields in Oman. Despite more than 35 years of production through various drive mechanisms, there remains an opportunity to realize significant additional value in the field. The scale and complexity of the uncertainties associated with such an opportunity necessitates the use of a structured approach to uncertainty handling. Experimental design and response surface-modeling methods provide a framework for evaluating sensitivities and estimating the impact of uncertainties on field performance. These methods require the *apriori* definition of the uncertainty range of key (or root) parameters and the construction of static reservoir models representing the full range of possible realizations. A selection of 3-D simulation models, as defined by the experimental design approach, were then run to construct response surface models, which are then used to assess the impact of these uncertainties on field behavior. The historical performance of the field is critical data that is used to constrain the range of some uncertainties. The results of this study are used to guide future development of the field. The methodology described in this paper highlights the value of a structured multiple realizations approach, using experimental design and response surface modeling, for uncertainty estimation and management.

Quantifying uncertainty in production forecast for fields with significant history: a West African case study (IPTC 10987)
Castellini, A., I. Gullapalli, V. Hoang and P. Condon (Chevron)

Understanding the impact of subsurface uncertainties on production responses is an integral part of the decision-making process. A more accurate quantification of the uncertainty band around production forecasts contributes to better business decisions. Traditional experimental design workflows, where a limited set of models represent the key uncertainties in subsurface parameters, might be well suited for new field developments. However, when a field has been produced for several years, all models have to be conditioned to available production data in order to obtain meaningful predictions. Data integration and uncertainty assessment of future performance of the reservoir are indivisible processes that cannot be generally addressed by simple techniques.

In this paper we present a method to tackle such complex inverse problems where highly non-linear responses are involved. The goal is to minimize an objective function that stands for the goodness-of-fit of the history-match. The key idea is to use high-quality proxies of the objective function to accelerate the search for solutions. An efficient experimental design stage allows for the selection of key parameters, while an optimization routine involving a Genetic Algorithms (GA) is used to determine the best combinations of parameters. The models that reasonably honor the historical data are selected and provide an estimate of future production. The final distribution of the prediction variables defines the range of uncertainty conditioned to production history. The practicality of the methodology is demonstrated with a study of an offshore field in West Africa that has several years of complex production history.

An integrated approach to waterflood management in a Paleozoic, high-viscosity oil reservoir: a case study of Haima-West Reservoir in a mature field in South Oman (IPTC 10330)
Chudhuri, B. and C.M. Steekelenburg (Petroleum Development Oman)

The Haima West reservoir in a mature field in south Oman showed severe production decline after initial encouraging results in re-development phase using horizontal injectors and horizontal producers. This sharp decline was due to rapid short-circuiting of injected water through possible presence of natural open fractures, induced fractures and/or thief zones. Further development of the reservoir was put on hold and an integrated well and reservoir management team was put in place to manage the waterflood with existing well stock and arrest production decline. The case study presents the successful implementation of a reservoir surveillance and optimization plan which could arrest production decline from the reservoir. Extensive data acquisition program during this phase to reduce uncertainty in the next phase of development is discussed.

A risk analysis approach: from subsurface to surface (IPTC 10493)
Contento, F.M., A. Godi, G. Nicotra and A. Pizzo (Eni)

The quantitative assessment of the risk associated with the economic exploitation of a hydrocarbon field is mandatory to support, in an efficient and comprehensive way, the decision process guiding the development management system of an oil company. The Full Range Risk Analysis approach developed in Eni E&P Division allows the identification of uncertainties arising from each step of an integrated reservoir study, and the evaluation of their impact on recoverable reserves and on the economic value of a project. This methodology has already been successfully applied in the concept selection and concept definition phases of field development projects. Recently it has been further improved to be employed both in the evaluation stage of a new discovery, and in the revamping of mature fields with production history.

The impact of water-injection-induced fractures on reservoir flow dynamics: first applications of a new simulation strategy (IPTC 10689)
Husstedt, B., Y. Qiu, D. Zwarts, L. van Schijndel and P.J. van den Hoek (Shell)

We present benchmark simulations and a real-field application of a new coupled fracture growth/fluid flow simulator. The coupled reservoir simulations compare well for various synthetic scenarios. The application to a real five-spot injection trial demonstrates the importance of the new modeling toll for optimal reservoir management.

Mature field revitalization using horizontal wells (IPTC 10008)
Mazouzi, A., K. Aissaoui and S. Bachiri (Sonatrach)

Hassi Messaoud oil field was discovered in 1956. With its reserves-in-place (OOIP) of several billion m^3, the Hassi Messaoud field is considered to be a giant. The large extension of the field, the presence of fault barriers and the lateral facies variation have confirmed nonuniform depletion throughout the field. The initial reservoir pressure was 482 bars and has been declining abruptly in some areas of the reservoir with field exploitation. The estimated low primary recovery by natural depletion has justified the requirement of applying an early enhanced recovery project. Considering standard screening criteria, miscible gas injection in some zones and water injection in others have been implemented. With time, field exploitation became complex with water and gas breakthrough.

In the past decade more than a hundred horizontal wells have been drilled, and the interest in re-entry of existing wells keeps growing. The objective is to develop the field's low permeability heterogeneous areas where sweep efficiencies and recovery factors using conventional wells are unsatisfactory. The extensive use of the technique appears to be a vital tool to economically extend the life of this maturing field, maintain its production plateau and achieve a high recovery rate. The horizontal well contribution to total field production keeps increasing. These are not only beneficial for productivity enhancement, but they also improve interwell reservoir characterization, identify fractures and lateral variation of facies, using data recorded along the laterals. This information will help to get more accurate reservoir model with usable uncertainty. This study evokes various technical issues related to the evaluation of production performances, decline and reservoir monitoring and forecasts optimization. It discusses in detail the results and highlights the experience learned from this technology.

3-D Geological modeling-drilling for geosteering (IPTC 10850)

Najjar, N.F. (Saudi Aramco); T. Jerome (Earth Decision Sciences) and M. Alshammery (Saudi Aramco)

The drilling of horizontal and multilateral wells has grown rapidly over the last decade. Successful geosteering of these wells in thin reservoir layers requires an accurate reservoir model that is updated in real-time with incoming logging-while-drilling (LWD) data. 3-D geological modeling-while-drilling workflows, which utilize geostatistical techniques, were developed to facilitate model updating, while improving the accuracy and reducing the cycle-time of the geosteering process. A data link between LWD tools in the field and Saudi Aramco's offices in Dhahran, provides real-time information to quickly update the 3-D earth model, enabling multidisciplinary geosteering teams to make fairly quick decisions regarding well-bore trajectory changes.

In the initial step of the modeling-while-drilling workflow, a sector model, which includes the planned horizontal well and neighboring wells, is extracted from the existing full-field 3-D geological model. Downscaling is applied to generate a fine-resolution model along the planned well path. Using nearby well data, the model is subsequently populated with reservoir properties such as porosity and gamma ray by means of variograms and geostatistical techniques, for instance Kriging or Sequential Gaussian Simulation (SGS). Pseudo well logs could be extracted along the planned well path for comparison with LWD measurements. The 3-D earth model is continuously updated during the drilling phase by automatically loading and integrating LWD data transmitted from the field. Quick model updating is done both for the structural and petrophysical components of the model. The new well data and revised earth model are analyzed in real-time, allowing the multidisciplinary geosteering team to quickly make changes to the planned well path and convey those changes to the drilling engineer at the rig.

Field examples in various geological settings are used to illustrate the modeling-while-drilling approach. It is an extremely useful technique that can be utilized to optimize well path, maximize well productivity, and reduce rig wait time. In addition, it allows professionals from different disciplines, whether in the field or geosciences centers, to work together in an integrated manner so as to reduce costs and improve well placement.

Steam injection in fractured carbonate reservoirs: starting a new trend in EOR (IPTC 10727)

Penney, R.K., R. Moosa (Petroleum Development Oman) and G.T. Shahin (Shell)

Significant volumes of heavy oil are still present in fractured carbonate reservoirs worldwide. Some of these reservoirs are good candidates for the application of thermally assisted, gas-oil-gravity-drainage (TA-GOGD), a novel EOR technique. Unlike a normal steam flood, the steam is used as a heating agent only to enhance the existing drive mechanisms. The elegance of TA-GOGD is that the fracture network is both used for the distribution of steam (heat) and the recovery of the oil. The number of wells can therefore be kept to a minimum compared to conventional steam floods. Following encouraging pilot results in a field in Oman, a steam-injection project is heading for implementation, a first of its kind on this scale. Studies to date indicate that recovery factors of 25–50% with oil-steam ratios of 0.2–0.4 m^3/ton of steam are feasible. The success of the project is critically dependent on the field-wide presence of conductive fractures and the ability to characterize them. Both stochastic and deterministic studies were tried, but the latter method is now favored as it allows the use of geological and dynamic understanding as input to the modeling and honors existing faults, deformation mechanism and the conceptual model. Fracture characterization is to some extent still an art and outputs are "only static scenarios". Therefore results should be validated with dynamic data as much as possible. The dynamic models are fully compositional, thermal and dual permeability, a complexity that is rarely encountered. Explicit fracture block models are used to verify that the heating rate and GOGD are captured properly, in particular for irregularly shaped fracture patterns. A new fully integrated workflow of fracture characterization with static and dynamic modeling will enable to manage uncertainties and risks in a scenario based approach.

Realizing the potential of marginal reservoirs: the Al Shaheen field offshore Qatar (IPTC 10854)
Thomasen, J. (Maersk); I.A. Al-Emadi and R. Noman (Qatar Petroleum); N.P. Ogelund and A. Damgaard (Maersk)

The oil-bearing reservoirs of the Al Shaheen field, Block 5 offshore Qatar were discovered in the mid-1970s in connection with appraisal drilling on the underlying North Field Khuff gas accumulation. However, at the time, development of the Lower Cretaceous Al Shaheen reservoirs was deemed unattractive due to their limited thickness and tight nature. Development of the reservoirs commenced in 1992, when Qatar Petroleum entered into an Exploration and Production Sharing Agreement with Maersk Oil Qatar AS. The giant Al Shaheen field comprises a series of thin, stacked reservoirs, dominated by tight carbonates with more permeable carbonate facies occurring over a limited part of the field. The reservoir sequence further comprises a very thin sandstone unit of variable quality. Following the discovery of the Cretaceous oil accumulation in 1974, a number of appraisal wells were drilled by various operators and comprehensive studies were conducted at the time in order to establish the feasibility of development. However, well tests in the vertical appraisal wells yielded discouraging results and it was concluded that development was not economically feasible. The main problem was that the majority of the oil-in-place existed in thin carbonates with low permeability. Combined with a relatively high oil viscosity, the vertical wells were unable to sustain natural flow and gave very low rates with artificial lift. Further, the hydrocarbon distribution was identified to be governed by non-horizontal fluid contacts due to considerable lateral pressure gradients in the liquid phases. This made prediction of the extent of the accumulation challenging.

Another difficulty was that the reservoirs covered substantial areas, and development would require a very large number of platforms, each connecting to a limited oil-in-place volume. This was further aggravated by the fact that the individual reservoirs did not overlay completely but rather spread over different areas. Finally, the fact the reservoirs were stacked and not in pressure equilibrium meant that attaining an optimal development of each individual thin reservoir layer and integrating all these developments in a cost-effective manner posed a major challenge.

The role of well testing in improving the productivity from a thin, tight, fractured and compartmentalized limestone reservoir (IPTC 10278)
Zubari, H.K., A.E. Al-Muftah, N.A. Qasim and A.E. Abdulwahab (Bapco)

This paper describes a creative and pragmatic approach that improved the production from one of the most difficult reservoirs in the Awali field of Bahrain. The Middle Cretaceous "Ab zone" is a thin, tight, highly faulted, and irregularly fractured limestone reservoir. The difficulty with this 15 foot, 1 md reservoir has prevented an efficient recovery. The average production of wells is 15 barrels of oil per day. This prompted a detailed integrated study plan to increase the wells' productivity. Well-testing was key to understanding the reservoir dynamics. A comprehensive well-testing campaign revealed a flow mechanism controlled by a fracture network. Fracture modeling and simulation failed to give clues on how to improve the productivity. However, the new approach that links transient well-testing and production data, with fracture network indications derived from seismic interpretations, has resulted in improving the productivity considerably. This was accomplished through re-entering old wells and designing special trajectories to intersect productive open fractures. The productivity was significantly increased to 60 barrels/day with sustained performance. The paper describes in detail our approach and methodology to understand the reservoir and its drive mechanism and to increase productivity and recovery starting from analyzing core data up to designing special configuration wells. The paper further highlights the pitfalls of the conventional workflow approach in modeling such difficult reservoirs.

RESERVES ESTIMATION

Restoring investor confidence in petroleum reserves worldwide-a joint effort by industry professionals (IPTC 10179)
Harrell, D.R. (Ryder Scott Company) and B. Dharan (Rice University)

How can an investor or anyone with an interest in oil and gas reserves be assured that an estimate was professionally prepared by qualified individuals, and in full compliance with the relevant definitions? In today's environment, we simply do not have such an assurance. Although many individual companies have developed their own internal standards, they vary widely from company to company and country to country. Standards established by the Society of Petroleum Engineers in 1977, describing the minimum qualifications for individuals estimating and/or auditing reserves estimates and reserves information, have been updated somewhat since that time, but remain inadequate in the opinion of many to meet the technological, regulatory and ethical challenges of today.

This paper presents the current status of an initiative generated in early 2004 and launched in September of that year by a group of professional geoscientists and engineers to both recognize and elevate the profession of petroleum reserves evaluation. The effort currently involves concerned individuals from across the energy spectrum working to launch a web-based program leading to the certification of qualified individuals in both geoscience and petroleum engineering. The certification program's sponsors are the American Association of Petroleum Geologists and Society of Petroleum Engineers, but other members and observers from a broad spectrum of the industry are also involved in the development. The comprehensive initiative includes steps to define a common body of knowledge for the reserves evaluation function, make available a complete set of training material, develop and oversee examinations required for certification, and develop other standards of ethical and professional conduct expected of the certified members.

Probabilistic reserve estimation constrained by limited production data: an integrated approach
(IPTC 10957)
Minhas, H., E. Matteo, K.M. Eikeland, M. Mengoli and S. Beswetherick (Eni-Agip)

Large uncertainties in structure and facies had been recognized in a major gas field in Pakistan after early production. The conventional reserve estimation methods had failed in providing a reliable estimate of gas-initially-in-place (GIIP). It was possible to get a good history match of one-year production data using a wide range of GIIP through a slight and acceptable adjustment of porosity and permeability. The resulting possible range of GIIP could easily vary by a factor of 1.5. Structural uncertainties did not warrant volumetric estimates either. Material balance technique was questionable due to non-uniform drainage of the reservoir. Clearly these deterministic techniques of reserve estimation were not applicable at this stage of production considering the complexities of the reservoir. A probabilistic technique was therefore developed that addressed both static and dynamic uncertainties in an integrated approach while honoring the available production history. Combined treatment of static and dynamic uncertainties also ensured a better coverage of the entire sample space, thus making the probabilistic approach more reliable.

Latin Hypercube Sampling (LHS) helped minimize the number of simulation runs while providing a reasonable coverage of the sample space. Yet we ended up with almost 1,500 simulation runs. The process of history matching, ranking and keeping track of all these simulation runs demanded an innovative workflow. A number of software tools were used to automate and optimize this process. Out of 1,500 simulation runs, the 200 best runs having the minimum objective function through history matching were selected. These runs were later used for production forecasting, for providing a range of reserves, and for sensitivity analysis to identify the most influential variables. Structure and NTG were identified as the two most critical variables for GIIP, while residual gas saturation was identified as an additional sensitive variable for reserves. Different geostatistical realizations had little impact on GIIP or reserves.

Deterministic approach had resulted in GIIP from 1 to 1.7 Reservoir Volume Units (RVU). Probabilistic estimates of GIIP, in comparison, ranged from 1.2 to 1.6 RVU. More important than a reduction in the range of reserves was the fact that this approach had considered all major uncertainties, static and dynamic, before estimating GIIP and reserves. At the same time, these reserves were in harmony with the actual field performance so far. This makes these numbers more reliable and the probabilities like P10 and P90 more meaningful.

Mature fields: the keys to winning the marathon
(IPTC 11040)
Saleri, N.G. (Saudi Aramco)

The term "mature fields" normally evokes connotations of rising costs and diminished expectations, yet the emerging subsurface, with its utterly different sets of rules and attributes, is changing our paradigms and spurring distinctly higher expectations. The increasing complexity of well architectures, higher levels of well intelligence and the real-time modality in well-placement and field operations, are all products of recent technological advances and specifically the "computer chip". Advanced diagnostics is fast becoming the norm. Do they assure greening of mature fields? What should be our redefined Expected Ultimate Recoveries (EUR's)? Is 90% of Theoretical Maximum Recovery Factor a sufficiently bold target to shoot for? What are the major impediments to achieving higher EUR's for mature fields? The answers invariably lie in modern reservoir management tenets, in-depth understanding of reservoir fundamentals, due-diligence provisions and a wise selection of "smart technologies" (the key operative word being "wise"). Saudi Aramco's portfolio hydrocarbon assets have, on average, a state of reserves depletion of less than 30%. On the mature end of the spectrum, Saudi Aramco's Abqaiq field has already crossed the 80% reserves depletion mark, yet is going strong on the strength of "smart technologies", and provides a real test as to what the smart technology dividend will be in terms of incremental recoveries and reduced costs.

Generation of probabilistic reserves distributions from material balance models using an experimental design methodology (IPTC 11009)
Vahedi, A., F. Gorjy, K. Scarr, R. Sawiris, U. Singh, P. Montgomery, S. Clinch and A. Sawiak (Chevron)

The Malampaya-Camago gas-condensate field is a Tertiary carbonate build-up that is situated offshore to the northwest of Palawan Island (Philippines) below 800–1,200 meters of water. It was discovered by Occidental in 1989 (Camago-1) and is operated by Shell (45%), Chevron (45%) and the Philippine National Oil Company (10%) as equity partners. The field has been supplying gas from five subsea production wells since late 2001 to three gas-to-power plants on Luzon Island. Available subsurface data include a 2001 high-resolution 3-D seismic survey, five production wells and six exploration/appraisal wells with wireline and borehole image data, including spot core in selected wells, pressure and well test data.

An extensive reservoir characterization study was carried out by Chevron on a non-operated asset in 2004, to determine gas-in-place and reserves distribution. This presentation outlines the Experimental Design (ED) methodology used in the study, which using material-balance models integrated the static and dynamic reservoir uncertainties with the excellent reservoir pressure history data that exists for the field. The methodology incorporated a unique and "state-of-the-art" method for screening over 20,000 reservoir realizations to allow only those realizations that showed a close match to the pressure history to be included in the generation of gas-initially-in-place and reserves distributions. This aspect of the Experimental Design methodology proved to be very powerful in generating reserves distributions in a "hands-off" approach without the requirement for traditional manual adjustment of reservoir parameters to obtain a history match.

Markov chain Monte Carlo methods for reserves estimation (IPTC 10065)

Wadsley, A.W. (Curtin University of Technology)

Monte Carlo methods are used to integrate the data pertinent to reserves estimation including material balance, production decline, reservoir volumetrics, and petrophysics. Many of these techniques produce independent estimates of reserves and hydrocarbons initially-in-place (HCIIP); for example, material balance and volumetric methods independently estimate HCIIP. Similarly, independent estimates for recovery factors are obtained from production decline, analogue reservoir studies and simulation. Traditional Monte Carlo methods are unable to combine such independent estimates in a natural way. Markov chain Monte Carlo methods, on the other hand, enable all such data to be integrated leading to robust, unbiased and accurate estimates of HCIIP and reserves. The algorithms for achieving this are presented and illustrated using field examples.

Reserves-getting it right (IPTC 10809)

Worthington, P.F. (Gaffney, Cline & Associates)

Reserve estimation can be based on static volumetric data, utilize reservoir simulation, incorporate a material-balance method, and/or draw upon projections of ultimate recovery according to production decline. The static volumetric method is the primary approach during the development and early production stages, when the uncertainty associated with a reserve estimate is greatest. Here, key technical aspects of the process include: (1) upscaling reservoir parameters and the interpretative algorithms through which they are interrelated; the issue of minimum data requirements in relation to reservoir complexity; (2) identification of net reservoir and net pay; and (3) the integration of data sources in a dynamically-conditioned manner. This last point is especially important, because reserves are by definition commercially recoverable. Suggested improvements reveal additional opportunities for cross-validation and ground-truthing. The approach is synthesized into a high-level, yet pragmatic workplan. It is proposed that adoption of such a workplan will reduce some of the uncertainty that is currently inherent in the technical process for estimating reserves.