Reservoir Characterization:
Integrating Technology and Business Practices

26th Annual Gulf Coast Section SEPM Foundation
Bob F. Perkins Research Conference

2006

Program and Abstracts

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Edited by

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Preface

As a company reservoir geologist in the mid-1980s, I still remember an incident when I jumped at the opportunity to geologically evaluate one of the largest oil fields in North America for equity re-determination. A younger colleague was displaced from an exploration group and assigned to help me on this project. He viewed this as a serious, though hopefully temporary demotion. His first comment to me was: "I was hired as an explorationist, and not to sift through oily dirt!" (The reservoir consists of unconsolidated oil sands). Such was the general feeling of geologists and geophysicists at the time—exploration was glamorous and required big, conceptual thinking, while reservoir description was, as the name implies, descriptive, mundane, and perhaps sufficiently numerical that it should be left in the hands of engineers, particularly since they are responsible for production from fields discovered by explorationists.

Fortunately, during the mid-late 1980s, some of the petroleum giants—such as the late Robert Sneider—were promoting the methods and applications of integrated reservoir characterization through society courses, publications, and sound business practices. In my own mind, the turning point from which "reservoir characterization" became something for geologists to avoid, to becoming a scientific discipline in its own right, was inauguration in 1990 of the ***Archie Conference*** series, vigorously pushed by Bob, and ultimately co-sponsored by American Association of Petroleum Geologists (AAPG), Society of Exploration Geophysicists (SEG), Society of Petroleum Engineers (SPE), and Society of Professional Well Log Analysts (SPWLA). The ***1st Archie Conference*** and resulting Proceedings volume were titled ***The Integration of Geology, Geophysics, Petrophysics, and Petroleum Engineering in Reservoir Delineation, Description, and Management***. This conference was not only an attempt to show the upstream petroleum community that professionals and their societies could work together, but to acknowledge the added value to the petroleum industry of discipline-integration. This conference provided the springboard from which the integration of disciplines in reservoir characterization evolved. Of course, the end-of-decade downturn in the industry also prompted professionals to take their skills from the exploration scale down to the reservoir scale.

Since the ***1st Archie Conference***, many additional conferences have been held, proceedings published, and books and papers written on the topic of reservoir characterization. Today, the stature and value of integrated reservoir characterization is well established and has become the norm in the global industry's attempt to produce more hydrocarbons from existing fields. Company annual operating budgets now include a substantial component for exploitation, in addition to increasingly-expensive exploration. This strategy by companies is important, if not critical. For example, one recent estimate of global production predicted a decline of 2-5%/year, which translates into an additional 10-19MMBOPD of additional production <u>required</u> by the year 2010 <u>just to stay even</u>. Much of this added production will have to come from mature or maturing fields, because they already have infrastructure in place, and because they typically retain more of their hydrocarbon supply than they release to producers. To accomplish this lofty goal, steady improvements in the ability to extract more hydrocarbons from existing fields at a reasonable cost are essential, rather than simply being good business practice.

This ***26th Annual GCSSEPM Foundation Bob F. Perkins Research Conference*** is a solid testimonial to how far we have advanced over the past 15 years in the technologies and practices of reservoir characterization for improved hydrocarbon recovery. The Call for Papers on the theme ***"Reservoir Characterization: Integrating Technology and Business Practices"*** was met with a wide range of presentations from outcrop studies to advanced numerical modeling of reservoir systems. A number of general observations can be made about the quality of the work being conducted within industry and academia, as revealed at this Conference:

- The majority of studies are now cooperative amongst the disciplines and clearly demonstrate the degree of discipline-integration that has evolved over the past 15 years;
- A variety of workflows have been developed by individual organizations for dealing with large datasets and diverse reservoirs, but a general theme of them all is discipline-, people- and data-integration;
- A comprehensive, useable characterization involves a major effort in terms of computing power and people's time, irrespective of the size of the reservoir under study;
- There is generally universal acceptance of the fact that reservoirs are almost always complex and compartmentalized;

- Outcrop analogs now provide an important input component to a characterization; lateral bed continuity and vertical connectivity in 3D space are particularly important to quantify;
- Proper characterization requires examination and study of a reservoir at all scales from the pore level to the field level; this can be a major challenge owing to time constraints in many fields and organizations;
- A variety of depositional processes and environments, as well as post-depositional burial processes, have resulted in a spectrum of reservoir types through geologic time; it is important that these different reservoir types be recognized and characterized at all scales. Generalized depositional models may exclude local heterogeneities that affect reservoir performance;
- 3D and even 4D seismic does not always provide the desired answer to reservoir performance. Features which control fluid flow are often beneath the resolution of normal seismic reflection volumes. However, advances continue to be made in forward and inverse seismic modeling to improve the information extracted from seismic;
- There are many risks and uncertainties associated with exploiting a reservoir, but the rewards can be substantial, though perhaps not as glamorous as a new exploration discovery;
- No matter how closely-spaced wells are, even in mature fields, there is still significantly more undrilled rock volume between and beyond the wells than has been drilled within the confines of the field. Thus, there is always a degree of uncertainty in predicting structural and stratigraphic features away from a wellbore.
- 3D geological modeling has attained a high level of sophistication, in terms of the modeling workflow, input parameters, and output used to simulate reservoir performance and develop a workable exploitation strategy. Improvements in 3D modeling and reservoir simulation software and computer horsepower/cost are major contributors to this improved sophistication in characterization and modeling. As demonstrated in some papers, 3D geocellular and reservoir simulation models being used today in large fields would not have been possible just a few years ago.

In an attempt to optimize knowledge transfer throughout the Conference, the thirty-seven, high-quality papers for presentation both orally and as companion posters have been grouped into six sessions. The first session begins after opening remarks and a thought-provoking introductory paper on the relative value of exploration and exploitation. The sessions, in their agenda order, are as follows.

Session I: Integrated Characterization of Developing Fields contains eight papers which describe the delineation and early exploitation phases of reservoirs in China, U.K. and Norwegian North Sea, Saudi Arabia-Kuwait neutral zone, Colombia, Venezuela, Mexico, and Indonesia. A variety of techniques, workflows and strategies are presented to resolve a variety of reservoir issues;

Session II: Geophysical Imaging for Characterization contains five papers dealing with seismic imaging and one paper dealing with borehole imaging. All papers combined present advanced processing and imaging procedures, and demonstrate the direction in which geophysical imaging continues to advance.

Session III: Integrated Characterization of Mature Fields contains five papers ranging from full-field modeling of the giant Prudhoe Bay Field to characterization of smaller gas-condensate reservoirs on the Texas gulf coast. Since there is not a universal definition of a 'mature field', I have single-handedly applied an 'age-since-discovery' factor in categorizing the fields for inclusion into this session.

Session IV: Outcrops and Modern Environments as Analogs for Characterizing Reservoirs contains six papers on both clastic and carbonate outcrops and sediments. This session demonstrates the level to which geoscientists working in surface environments have reached in their use of a variety of techniques to quantify stratigraphic properties for application to subsurface reservoirs. "*Seeing is believing*" is the key principle behind surface characterization, because subsurface techniques cannot image all of the potentially-important heterogeneities within a reservoir.

Session V: Modeling for reservoir development and assessment of uncertainty and risk contains nine papers which collectively demonstrate the high level of efficiency and cooperation that have been achieved in the quest for quantitative 3D geological models for reservoir performance simulation and exploitation management. Papers include the application of integrated datasets/people, geostatistics, upscaling, history matching, and sedimentary process-response modeling, with emphasis on quantitative 3D geological models. The variety of approaches being utilized in this model-building endeavor are both informative and thought-provoking. Comparing the current state of 3D geological modeling with efforts of just a few years ago makes one wonder what will be the next incremental and/or quantum advancement in modeling, and how far the science can excel.

Session VI: Improvements in reservoir characterization and well planning is the closing session. It contains three informative papers summarizing recent, specific advances in aspects of well planning and characterization that may not be familiar with the majority of attendees and readers.

The planning committee for this Conference is confident that its goals have been met. New ideas, workflows, and methodologies are provided which can not only be used daily in the workplace, but equally important, which can provide the foundation for the next generation of advances in the science of reservoir characterization. Some of the thoughts for future work that I came away with after organizing and reading each contribution are the need for:

- advances in computing power so that less up-scaling is required for simulation;
- continued progression of geophysical imaging technology in order to capture important "sub-seismic scale" features;
- continuation of 3D quantitative outcrop characterization for geologic modeling;
- significantly more integration of high-resolution biostratigraphy and geochemistry into the reservoir characterization workflow;
- continuation of the phenomenal growth and abilities of quantitative 3D static and dynamic geological modeling;
- improved realization by company management that completion of a proper characterization requires more time than is often allotted (i.e. the industry-wide' 80% rule' may not be sufficient when reservoir performance is controlled by hard-to-pinpoint heterogeneities);
- a better understanding of 'what really matters' in reservoir characterization.

The only minor disappointment was the relatively small number of papers that included discussion of the business side of reservoir characterization, as was requested by the title of the Conference. However, technical people are what they are, and the technical advances in the science of reservoir characterization that are presented at this Conference bode well for the future, as more focus is placed upon enhanced hydrocarbon recovery from existing reservoirs.

Finally, I and the organizing committee would like to take this opportunity to thank all of the contributors to this Conference who took time away from their busy work schedules to prepare papers. We also thank Carol Drayton for her layout and editing expertise, Andrew Slatt for re-drafting a number of graphics that required touchup for this Proceedings volume, Gail Bergan for formatting and completing the Proceedings volume, and Norm Rosen, as Executive Director of GCSSEPM, for his monumental effort at guiding this Conference to success. Reviews of first draft papers were completed by organizing committee members.

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Cover Image

The cover image chosen for this year's conference is from van Hoek and Salomons: "Understanding the Seismic Expression of Complex Turbidite Reservoirs Through Synthetic Seismic Forward Modeling: 1D-Convolutional Versus 3D-Modeling Approaches," Figure 4A, this volume.

Reservoir Characterization:
Integrating Technology and Business Practices

26th Annual Gulf Coast Section SEPM Foundation
Bob F. Perkins Research Conference

Houston Marriott Westchase
Houston, Texas
December 3–6, 2006

Program

Sunday, December 3, 2006

4:00–6:00 p.m. Registration (Grand Foyer) and Poster Setup (Grand Pavilion)

6:00–8:00 p.m. Welcoming Reception and Poster Preview (Grand Pavilion)

Monday, December 4, 2006

7:00 a.m. **Continuous Registration (Grand Foyer)**

8:00 a.m. **Welcome: Paul Weimer, Chairman of the Board of Trustees, GCSSEPM Foundation (Grand Pavilion)**

9:40 a.m. **Guargena, Claudia G.; Perry, Sonja; Gjerdåker, Lars; Hamre, Helge; Horvei, Nils Aksel; Nystrand, Bjørn Velle; and den Ouden, Ron**

10:05 a.m. Refreshment Break and Posters

10:30 a.m. **Meddaugh, W. Scott and Griest, Stewart D.**

10:55 a.m. **Mendez-Hernandez, Efrain; Bahamon-Velasquez, Carlos; Slatt, Roger M.; and Garcia-Hernandez, Jesús**

11:20 a.m. **Cortes, Rodrigo Bastidas; O'Meara, Daniel J.; and Slatt, Roger M.**

11:45–1:15 p.m. Lunch and Open Poster Booths

Session I—Integrated Characterization of Developing Fields (continued)

Chairman: M. Burnett

1:30 p.m. **Gamero, Helena; Perdomo, Jose Luis; Laporte, Lucienne; Rodriguez, Freddy; Rahn, Tami Chism; and Isakson, Christina**

1:55 p.m. **Suta, I Nyoman; Utomo, Budi Tyas; and Slatt, Roger M.**

Session II—Geophysical Imaging for Characterization

Co-Chairmen: M. Burnett and J. Hooper

2:20 p.m. **Bastia, Ravi**

2:45 p.m. **van Hoek, Tomas and Salomons, Boudewijn**

3:10 p.m. **Nivlet, Philippe; Lucet, Nathalie; Tonellot, Thierry; Lerat, Olivier; Lefeuvre, Frédéric; and Piazza, Jean-Luc**

3:35 p.m. Refreshment Break and Posters

Tuesday, December 5, 2006

Session III—Integrated Characterization of Mature Fields

Co-Chairmen: R. Loucks and S. Phillips

10:05 a.m. Refreshment Break and Posters

Session IV—Outcrops and Modern Environments as Analogs for Characterizing Reservoirs

Co-Chairmen: M. Scheihing and M. Tomasso

Wednesday, December 6, 2006

Session V—Modeling for Reservoir Development, and Assessment of Uncertainty and Risk (continued)

Co-Chairmen: J. Chen and S. Meddaugh

Session VI—Improvements in Reservoirs Characterization and Well Planning

Chairman: R. Slatt

A Closer Look at Field Reserve Growth: Science, Engineering, or Just Money?

Grace, John D.
Earth Science Associates

Abstract

The growth in estimated ultimate recovery (**EUR**) of oil and gas fields over the course of their development has been recognized as a significant contributor to hydrocarbon supply, both in the United States and abroad. Data on changes in **EUR** have been examined for oil and gas fields discovered on the modern shelf of the Gulf of Mexico, in order to empirically determine the possible causes of these changes.

Using a semilog regression model of **EUR** as a function of years since discovery, from 1975 through 2002, roughly half of fields in the study area grew and the balance either shrank or remained statistically unchanged. Fields that grew were typically large discoveries to start and the volumes by which they grew were log normally distributed. The fields making the largest contributions to aggregate growth typically had at least 20 reservoirs over at least 5,000 feet of charged section, which was deposited in generally progradational environments at sediment accumulation rates between 500 and 2,500 feet per million years.

The principal mechanism of field growth in the study area was through the discovery of new reservoirs. In the fields having the largest growth, these discoveries occurred in cycles based on stratigraphic interval. Within each cycle, the largest reservoirs were discovered early and the size of reservoir discoveries declined exponentially. Up to four major stratigraphically based cycles were observed; generally, but not always, each subsequent cycle added a smaller volume to **EUR** than those that preceded it.

A secondary source of growth arises through the combined effects of recognizing an increased volume of reservoir rock containing reserves and improvement in recovery factors. The contributions of these mechanisms have been examined through analysis of single-reservoir fields and growth in fields after their last new reservoir discovery.

Field growth is tied to the economic conditions surrounding oil and gas production. From the mid-1970s through mid-1980s, during a period of rising and high prices, large increases in oil and gas reserves were gained through new field discoveries, discovery of new reservoirs within fields and, to a lesser extent, positive reservoir volume revisions and increases in recovery factors. Price collapses in 1986 and again in 1998 are both reflected in reductions in field growth and actually declines in aggregate **EUR**.

Although a short time series, **EUR** growth between the beginning of the current price recovery in 1998 and 2002 indicates that supply of new oil and gas in existing fields is becoming more inelastic. This is most probably due to two factors: depletion of the growth potential of old, very large fields; and because of the progressive decline in the sizes of new field discoveries and the high correlation between size and growth, as newer finds have smaller growth potential.

Reservoir Characterization of Fluvio-Lacustrine Sandstone Deposition and the Impact on Field Economics, Daan Field, Songliao Basin, P.R. China

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Sneider Exploration
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Xuehui, Yu
MI Energy Corp

Deyu, Ning
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Abstract

Since 2001, MI Energy - PetroChina partnership has drilled 400 wells at Daan Field, Songliao Basin, Jilin Province, Peoples Republic of China (Fig. 1). The main reservoir objective is the Cretaceous FuYang fluvio-lacustrine sandstone. The reservoir has relatively low porosity (10-18%), low permeability (<1-30mD), and has dramatic changes in reservoir quality over short lateral distances (Figs. 2 and 3). Accurately predicting reservoir distribution is crucial for successful field development.

FuYang sands were deposited in a half-graben bounded by the Daan fault to the east. FuYang sands accumulated in north- or northeast-trending depocenters, parallel to the Daan fault. The graben was inverted during the Tertiary along the Daan fault, forming the Daan anticline which is the trap for the field. The FuYang reservoir in the Daan Field area is subdivided into approximately 25 stratigraphic intervals that may contain reservoir quality sandstones (Fig. 3). Reservoir sandstones are not developed for each interval at every location in the field.

The FuYang reservoir is distributed in a series of north- or northeast-trending sand thicks or “Sweet Spots” that measure about 700m by 3000m and have total pay thicknesses of 10m to 35m (Fig. 4). Average permeability X net pay thickness (*kh*) (Fig. 5) and hydrocarbon pore volume show similar trends (Fig. 6). Typical “Sweet Spot” wells have 10 sand zones ranging in thickness from 1m to 10m. Sedimentary facies are fluvial (*e.g.*, channel bars, crevasse splays) to marginal lacustrine (*e.g.*, distributary channels, mouth bars). The top of the FuYang is marked by an abrupt deepening of the Daan Lake, which corresponds to a Songliao Basin maximum drowning event and deposition of the basin's main source rock.

When the MI Energy - PetroChina partnership began operations in Year 2001 at Daan, 40 wells had been drilled already in the field, and the model for reservoir distribution was based on a concept of east-west regional dip and east-west trending reservoir sand bodies (Fig. 7). Early appraisal wells often had disappointing results and reservoir prediction was poor. However, a detailed study of reservoir data from wells in the most densely drilled part of the block, the Da206 area, revealed north- or northeast-trending reservoirs (Fig. 8). Drilling results and reservoir prediction improved in Year 2002 when the north- to northeast-trending reservoir model was incorporated. Average net pay increased from 12.5m to 19.5m and average new well production increased by 21%, from 6384 **BO** to 7737 **BO** for the first six months of cumulative production (Fig. 9). In Year 2003, new well production increased by a further 24%, to 9619 **BO** for the first six months of cumulative production.

During Year 2004, as field development pace accelerated dramatically and rig utilization pressure increased, drill locations were frequently selected on a grid system basis rather than on a geologic reservoir prediction basis. As a result, new well production dropped by 51%, to 4694 BO for the first six months of cumulative production (Fig. 9). Upon recognizing the poorer results of the Year 2004 drilling program, a renewed effort began to select well locations on a systematic geological basis. A system of quarterly well location selection meetings was instituted. At the quarterly meetings, results of the prior quarter’s drilling were summarized on reservoir distribution maps of net pay thickness, hydrocarbon pore volume and *kh* (average permeability times net pay thickness), and these maps were used to select optimal locations for the next quarter’s drilling program. This systematic approach resulted in improved drilling results in Year 2005, with an average new well production increase of 47%, to 6920 **BO** for the first six months of cumulative production (Fig. 9).

Understanding and Modeling Connectivity in a Deep Water Clastic Reservoir—The Schiehallion Experience

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Abstract

Schiehallion is a two billion barrel deepwater clastic reservoir, situated on the Atlantic margin of the **UKCS**, one of the world's most hostile environments for hydrocarbon production. The field has been developed via subsea wells tied back to an **FPSO**, and is one of the first developments of its kind anywhere in the world.

The field may be characterized as high productivity but low energy and, as a consequence, water injection is essential to maintaining production. However, the reservoir is channelized, faulted, and has varying degrees of connectivity between the compartments, so that a good understanding of these factors is necessary to optimize the water injection distribution.

Our understanding of the 'plumbing', or connectivity between the wells, has evolved and matured over time, using a wide range of different data types, from the initial extended well test, through **RFT's**, pressure transient analyses, interference testing, **PLT's**, tracer and geochemical sampling, to bi-annual 4D seismic surveys using increasingly sophisticated processing and interpretation.

Much of this understanding has been incorporated in a 3D model, which uses object modeling and seismic conditioning to represent the sand distribution. Potential barriers to flow are identified from seismic coherency analysis, and the strengths of these barriers have been used as the main history matching parameters.

A key learning has been that all data needs to be interpreted with great care, and it is essential to integrate several data types in order to obtain reliable conclusions. The paper gives examples of data which has been invaluable, as well as examples where the data is ambiguous or misleading.

Reservoir Characterization—An Integral Aspect of Uncertainty Management for Opportunity Realization at the Ormen Lange Giant Gas Field Development, Norwegian Sea

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Abstract

The Ormen Lange gas field, discovered in 1997 (Hydro operated License PL209) in 1000 m (3,281 ft) water depth and covering an area of ca. 350 km^2 (217 mi^2) was further appraised by four wells prior to development approval in April, 2004. The partnership, Hydro (development operator), Norske Shell (production operator), Petoro, Statoil, ExxonMobil, and Dong, had a planned production-start in October, 2007, from 8 of 28 possible production wells in a staged development using four subsea templates. The development faced a number of challenges; rough seabed topography, subzero sea bottom temperatures, harsh ocean conditions and a change of operatorship at production start-up.

Reservoir characterization of the areally limited, but intensely faulted turbidite reservoir has formed an integral part of the work flows. These work flows address the uncertainty of vertically and horizontally connected reservoir volumes for productivity at well targets. Model scenarios have been constructed in a 3D visualization environment where optimal integration of a multitude of seismic data volumes, derived attributes, and geological model concepts has been achieved. The roughly polygonally distributed faults are not expected to be sealing; having developed close to sea bed, their origin rules out cataclasis and cataclasis-enhanced cementation. The common gas gradient and absence of measurable depletion during well tests support non-sealing faults and vertical connectivity. However, dynamic fault seal uncertainties related to reservoir heterogeneity and compartmentalization have necessitated risking the relatively simple tank scenario and a more cautious, stepwise approach for the development concept. A significant opportunity can be realized if the gas can be produced profitably using only three templates.

A Design of Experiments-Based Assessment of Volumetric Uncertainty During Early Field Delineation and Development, Humma Marrat Reservoir, Partitioned Neutral Zone

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Abstract

A consistent design of experiments (**DoE**) based evaluation process was used to assess the magnitude of **OOIP** uncertainty as well as the relative contributions from uncertainty sources as a function of the historical development of the Jurassic Humma Marrat carbonate reservoir in the Partitioned Neutral Zone (**PNZ**). Within the Marrat interval, three stratigraphic layers, known informally as the A, C, and E zones, produce oil. Porosity and permeability is best developed in the dolomitized lowermost Marrat E interval. Based on limited data, approximately 80-85% of the current oil production is from the E zone and 10-15% from the A zone. The C zone contribution is 5% or less.

The uncertainty sources used in the **DoE**-based evaluation were: structure (time-to-depth conversion and overall interpretation uncertainty), original oil-water contact (**OOWC**), porosity histogram, and oil saturation histogram. All of the uncertainties except structure were evaluated for each of the three stratigraphic zones known to produce oil in the Marrat. High, mid, and low-case values were determined for each of the uncertainty sources listed using well log, core, and analog information available after each well was drilled or as significant new data became available (*e.g.*, reprocessed seismic volume). The time period covered by this historical look-back is from 1998 (pre-drill) to 2005.

The pre-drill P_{50} **OOIP** estimate for the Humma Marrat was about 900 million reservoir barrels. Following drilling of the initial two wells, the P_{50} **OOIP** estimate was < 400 million reservoir barrels. Subsequent drilling and structure modifications (interpretation and time-to-depth conversion) increased the P_{50} **OOIP** estimate to just over 1500 million reservoir barrels in April 2004. The P_{50} **OOIP** was dropped to 625 million reservoir barrels after Well F was drilled in mid-2005. The **OOIP** uncertainty range, defined as the P_{90} **OOIP** value minus the P_{50} **OOIP** value, decreased from nearly 700 million barrels in 2004 to about 130 million barrels in mid-2005. Analysis of the **DoE**-based results show that the significant contributors to **OOIP** uncertainty changed as additional wells were drilled or existing data was re-processed or re-interpreted. However, the structure and/or **OOWC** uncertainties were generally the largest, though not necessarily always statistically significant contributors to **OOIP** uncertainty (based on a 95% confidence level). A normalized uncertainty index (**UI**) derived from the probabilistic **OOIP** values is used to discuss delineation efficiency and may be useful in delineation well planning.

Workflow for Integrated Characterization of Combination Structural-Stratigraphic Traps: Example from the Southern Gulf of Mexico

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Abstract

An integrated workflow has been developed that successfully characterized a new gas reservoir in the southern Gulf of Mexico, which is utilized to improve reserves estimation, reservoir development, and management planning. The reservoir intervals were contained within a faulted rollover anticline. Based upon development of a sequence stratigraphic framework, the reservoirs were identified as retrogradational shoreface parasequences sitting atop third-order sequence boundaries. **AVO** and spectral analysis of the seismic volume provided support for this interpretation. A new play concept was developed which incorporated sequence stratigraphy and analysis of 3D seismic attributes for more regional mapping in the area. Recommendations for well stimulation also were made based upon stratigraphic aspects of the rocks.

Evaluating Fault Compartmentalization by Integrating Geologic, Geophysical and Engineering Data: A Case Study from South America

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Abstract

A set of seismic, well log, core, petrophysical, and well test data was integrated to construct a 3D geological model for reservoir characterization and later performance simulation. The model was initially built to address the unexpected performance of a single well. This well was designed as a water injector but produced sufficient oil to be deemed a producing well. The model explained the reason for this unexpected behavior—the reservoir was compartmentalized into fifteen fault blocks, many of which were not in mutual communication. Also, individual fault blocks were stratigraphically compartmentalized. The case for compartmentalization was built upon analysis of log-derived Leverett **J**-Functions and petrophysical and well data, all within the context of a 3D geological model constructed in **GoCad**™.

This case study serves as an example of the value of integrating available data to develop a 3D geological model which can address short-term production issues, broader performance issues, and infill drilling opportunities, all of which may be affected by compartmentalization.

Three-Dimensional Reservoir and Simulation Modeling Workflow of Hyperpycnal Systems: A Case Study of LAG-3047, Block X, Misoa Formation, Maracaibo Basin, Venezuela

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Abstract

The Eocene Misoa Formation is a prolific producer of hydrocarbons in the Maracaibo basin and traditionally has been interpreted as being deposited in a fluvio-deltaic depositional system. Sedimentological interpretation of 1,534 ft (467.6 m) of core has led to the development of a new depositional model. The Misoa Formation C sands in the LAG-3047 area have been reinterpreted as being deposited from sustained fluvial-derived hyperpycnal flows. The conceptual hyperpycnal model has been used to guide correlation of 21 wireline logs and to provide a high-resolution stratigraphic model of the lower C Misoa sands. A geostatistical approach was used to propagate the facies and the petrophysical properties in the geological model. However, some difficulties were encountered for propagating hyperpycnal channelized-lobe systems, since a standard object-modeling algorithm is useful only for fluvial systems. An alternative three-step methodology was developed to model channelized-lobe systems which proved to be very successful. Forty realizations of the geological model were generated to assess the uncertainty in the distribution of channelized-lobe systems between wells. Simulation was used to rank the realizations; the best realizations were chosen by historical pressure and production. Two upscaled grids were generated for simulation and prediction. The hyperpycnal depositional model aided in the simulation calibration process because reservoir compartments were easily modified to match the historical pressures and therefore connected reservoir pore volumes. At the end of the calibration process, these reservoir compartments could be used to define whether new wells would be likely to contribute to the proposed waterflood or to access new reservoir pools.

Integrated Characterization for Development of the Northeast Betara Field, South Sumatra Basin, Indonesia

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Abstract

Northeast Betara Field, located in the south Sumatra basin of Indonesia, is a fault-bounded reservoir comprised of the Oligocene lower Talang Akar Formation. The reservoir consists of two fluvial facies, a lower braided river facies and an upper meandering river facies. Both facies are separated by areally extensive floodplain/marine shale. Based upon both sequence stratigraphic and structural analysis of 3D seismic and well/core data, the distribution of braided river facies is controlled strongly by block faulting coupled with a significant drop in relative sea level. During subsequent early rise in relative sea level, reservoir sands have been re-cycled and reworked to provide better reservoir quality of the upper meandering river sandstones. This facies has tested >1400 **BOPD**, >10 **MCFGPD**, and some condensate from NEB #7 well.

The Northeast Betara Field is highly compartmentalized both structurally (faults and folds) and stratigraphically (discontinuous sandstones and shale interbeds). The field consists of separate oil and gas-condensate reservoir systems. Volumetric reserves calculation, combined with material balance studies, indicate the potential oil reserves comprise approximately 10 to 15% of the total potential gas-condensate reserves.

Recognition of reservoir compartments having varying fluid contacts constitutes an important inter-well frontier for development of Northeast Betara and other, similar fields in the area. Compartments have been identified using the integrated methodology described here. In structurally and stratigraphically compartmentalized reservoirs such as Northeast Betara Field, development of an integrated 3D geologic model, numerical reservoir simulation model, and production strategy has been critical to optimize both oil and gas production. Oil rim reserves have been produced in the early stage of development, followed by current production from the main gas-condensate reservoir.

High-Quality Techniques of Subsurface Imaging and Reservoir Mapping of the Deep-Water Neogene Depositional Systems in Krishna-Godavari Basin, East Coast of India

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Abstract

The east coast of India represents a passive Atlantic-type peri-cratonic margin setup. The Krishna-Godavari basin along the east coast of India covers the deltaic and inter-deltaic areas of Krishna and Godavari rivers and extends into the offshore; it has an area of 1,45,000 sq. km. The basin evolved through crustal rifting and subsequent drifting during Mesozoic time, followed by major fluvial and marine Tertiary sedimentation.

A geologic model has been constructed for Neogene deep-water depositional systems in the Krishna-Godavari basin to conceptualize the reservoir architecture of complex channel-levee, overbank, and lobes on the shelf-slope geologic setting. While the channel-levee deposits are dominated by siltstone/ sandstone prone facies assemblages, the lobes are predominantly fine-grained sandstone/ siltstone/ mudstone facies. High quality 3D seismic imaging and interpretation techniques, integrated with wire-line logs, litho-cuttings and cores have been followed in characterizing the complex deep-water reservoirs. The study integrates different data sets and methodologies such as (1) high quality 3D seismic with rigorous quality control in acquisition and processing using interactive geological input; (2) imaging enhancement through pre-stack depth migration of selective areas; (3) extensive use of rock-physics attributes through inversion and **AVO** studies; (4) detailing of depositional architecture through stratal-amplitude attribute, spectral decomposition, and coherency slices; (5) high resolution wire-line logs and analysis; (6) detailed petrophysical and petrological evaluation of conventional cores, and (vii) quantitative computation of reservoir properties and improving bed resolution through simultaneous angle dependent inversion.

Understanding the Seismic Expression of Complex Turbidite Reservoirs Through Synthetic Seismic Forward Modeling: 1D-Convolutional Versus 3D-Modeling Approaches

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Abstract

Synthetic seismic forward modeling has been used for many years to gain a better understanding of the seismic expression of subsurface geology and to ensure consistency between quantitative models and available data. With improvement in static model-building capabilities, increased computing power, and the ongoing need to optimally use seismic information to condition exploration and production models, synthetic seismic modeling approaches have evolved towards 3D modeling of realistic and complex input models.

The 1D-convolutional method of generating 3D synthetic seismic models is computationally very fast and convenient to apply. However, influences of spatially varying lateral resolution, acquisition, processing, and overburden effects on the resulting seismic image are fully or partially neglected. Given the simplifying assumptions of the 1D-convolutional modeling method, it is important to understand the degree to which results are representative of the actual seismic expression of the subsurface geology. It is desirable to know under which circumstances the 1D-convolutional approach can be assumed to be a sufficiently close approximation and under which conditions the more sophisticated 3D techniques are required.

As a contribution to addressing this question, two suites of 3D synthetic seismic models were constructed from high resolution, realistic, and representative static facies models of complex turbidite reservoir architecture; one using the 1D-convolutional method and the other employing a 3D-modeling technique. The latter approach honors lateral resolution, processing, acquisition, and overburden effects. Comparison of results of the two methods suggests potential pitfalls in applying inferences from the 1D method in reservoir characterization (*e.g.,* lithofacies distribution, net-to-gross, and connectivity).

Integrated Reservoir Model: Lithoseismic Interpretation and Definition of the 3D Seismic Constraint

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Abstract

A methodology devoted to the integration of seismic information within the geological stochastic modeling workflow has been developed in order to optimize the characterization of small scale internal reservoir heterogeneities.

The workflow consists of three stages detailed here and in a companion paper in this volume (Lerat *et al.*, 2006):

- Litho-seismic interpretation and definition of the 3D seismic constraint;
- geostatistical geological modeling using a 3D seismic constraint; and
- reconciling seismic data with the geological model.

In this paper, we present the interpretation of seismic data in terms of 3D geological facies proportions at Girassol, a large and complex turbidite field located offshore Angola. This type of interpretation requires high quality seismic data, which was the case in the present case-study. Secondly, particular attention has been paid to calibration issues: for wells with available sonic data, vertical and lateral shifts have been determined at early stages of the analysis to ensure optimal local consistency between well logs and local seismic amplitudes. For the other wells, an optimal location has been found *a posteriori* by comparing electrofacies analysis results with geological facies proportions predicted from seismic.

The proposed workflow integrates knowledge from various sources and with different spatial resolution and support: pre-stack seismic amplitudes and velocities, well logs, stratigraphy, and structural information. It is divided into three parts.

- Pre-stack stratigraphic inversion;
- Probabilistic seismic facies analysis from the inversion results based on discriminant analysis; and
- Computation of geological facies proportions from the previous results by a novel approach developed to account for scale differences between seismic facies and detailed geological facies description, in order to produce a geologically interpreted 3D model of the reservoir to be used in further steps of the reservoir modeling workflow.

Application of Volumetric 3-D Seismic Attributes to Reservoir Characterization of Karst-Modified Reservoirs

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Abstract

Reservoir production and compartmentalization in many karst-modified reservoirs can be related to features resulting from subaerial weathering, tectonic faulting and fracturing, and/or hydrothermal processes. Critical features relating to reservoir character are often subtle and are difficult to image with standard seismic attributes. We have developed new 3D seismic-based geometric attributes that, calibrated with geologic and engineering data, have the potential to image and quantify karst-modified reservoir features at an interwell scale not previously possible. Our aim is to develop innovative seismic-based methodologies and workflows for reservoir characterization of karst-modified reservoirs.

We have applied our new seismic attributes to reservoirs in Kansas, Colorado, and Texas that represent a diversity of ages, lithologies, karst processes, and porosity/permeability systems. In these reservoirs, we have mapped horizon structure, faults, and fractures with a combination of conventional seismic data, coherency, and new volumetric curvature attributes. Using horizon extractions and time slices, we have imaged the geomorphology of eroded surfaces and identified subtle attribute lineaments associated with faults and fractures that relate to reservoir production and compartmentalization. We predict azimuths of open and closed fractures by matching rose diagrams of attribute lineaments with strain ellipsoids, by calibrating to wellbore data, and by relating attribute lineaments to produced fluid volumes. We use improved spectral decomposition and acoustic impedance inversion technologies to image porosity variations in the reservoir.

Our attribute-based structural and stratigraphic models, populated with borehole and engineering data, serve as the basis for improved geomodels that we validate with reservoir simulation.

Enhanced Reservoir Characterization Using Spectral Decomposition and Neural Network Inversion: A Carbonate Case History from the Chiapas of Southern Mexico

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Abstract

A reservoir study was conducted at Gaucho Field in the Chiapas of Southern Mexico, the primary objective of which was to determine porosity in the base of the upper Cretaceous carbonate in order to facilitate further field development. Conventional seismic impedance inversion alone did not adequately predict porosity nor did neural network predictions using conventional seismic attributes. Spectral decomposition and neural network inversion were integrated to produce an estimated porosity cube at the target level that provided excellent porosity indication in validation wells. The lateral variation of porosities within the area ranged from about 2% to more than 30%. Thus, the application of these techniques allowed final adjustment of drilling locations, in order to capture the maximum local porosity possible. Resulting porosity maps within the field area are shown to have important implications for field development and further exploration in this area.

For spectral decomposition, this study illustrates the relationship between porosity thickness and peak frequency and between the magnitude of the average effective zone porosity and peak amplitude. Additionally, the study demonstrates the importance of training a neural network properly with (1) appropriate input attributes and (2) utilization of wells which cover the spectrum of possible porosity encountered in the area. We show how such a methodology can be applied to similar carbonate reservoirs so as to distinguish locations having minimal to no effective porosity from areas having excellent porosity where additional development drilling can be fruitful.

The aim of this paper is to showcase an integrated workflow for this type of study, rather than to focus on results.

Reservoir Characterization Applications of Electrical Borehole Images

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Abstract

Since the introduction of electrical borehole images over twenty years ago, many very useful applications have been developed for this data. Some of these applications range from hand-picked bed dips to fracture analysis; from thin-bedded pay determination to vugular porosity measurement; and from fault geometry determination to facies analysis. These applications are made possible because of the high resolution provided by these images.

Electrical borehole images provide the means to perform detailed high-resolution reservoir characterization at and adjacent to the borehole. This paper addresses several of these applications, which give the geologist, petrophysicists, and reservoir/production engineer a means to evaluate their reservoir and make decisions ranging from setting pipe, to completion strategy, to offset well placement. Various images of thin bedded formations, slumped zones, fractured intervals, and faulted and folded intervals are shown along with the associated interpretations. Also, a series of images, coupled with corresponding outcrop and/or core photos, is provided of deep-water deposits. Implications of reservoir behavior and the required action to efficiently produce the reservoir are included.

Waterflood Optimization in Low-Permeability Turbidites of the Long Beach Unit, Wilmington Field, California[1]

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Abstract

The **U-P** Ford zone in the Long Beach Unit of the East Wilmington Field consists of low-permeability (2-50 millidarcies) turbidites that have been waterflooded since field start-up. Forty years of successes and failures have provided valuable insights into how to best waterflood these reservoirs given their thin-bedded nature, lateral and vertical changes in reservoir quality, formation damage susceptibility, and sand control problems. Multiple techniques and technologies have been applied to describe their reservoir architecture, quantify reservoir performance, and extract the oil. This work has become more challenging as the waterflood has matured and will require the close integration of all disciplines to identify and exploit remaining opportunities.

1. Updated from SPE 92036, "Forty Years of Improved Oil Recovery: Lessons from Low-Permeability Turbidites of the East Wilmington Field, California", presented at the SPE International Petroleum Conference, Puebla, Mexico. Copyright 2004, Society of Petroleum Engineers Inc.

Challenges of Full-Field Modeling a Giant Oil and Gas Field: Prudhoe Bay Field, North Slope of Alaska

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Abstract

Prudhoe Bay Field, the largest non-heavy-oil field in North America, has produced about 11 billion of 25 billion barrels of oil-in-place since production began in 1977. Co-owners ExxonMobil, ConocoPhillips, and BP made the decision to build a new full-field model to evaluate future development decisions in the field. Requirements for the full-field, 12-component reservoir simulation model included a model size limit of about one million active cells and an areal grid block resolution of 5 acres (467ft / 142m X 467ft / 142m) and 10 to 15 feet (3.0m to 4.6m) vertically. The model incorporates approximately 2600 wells (about 1000 of which are horizontal), 1800 faults, all productive reservoir zones and other important geological controls on fluid flow such as shales and conglomeratic thief zones. A team composed of BP's Alaskan geological, geophysical, petrophysical, and reservoir engineering staff; geocellular modelers from the three partner companies; and a consultant reservoir simulation engineer was assembled to build the model. The inclusion of operating company geoscience and engineering staff contributed specific expertise in the geology and reservoir engineering of Prudhoe Bay Field. The inclusion of multiple geocellular modeling staff contributed "best practices" from each partner company and also allowed key parts of the model, such as the structural framework and properties model, to be built concurrently, thus saving substantial time. The inclusion of the consultant reservoir simulation engineer having extensive experience with previous Prudhoe Bay full-field models provided continuity with prior modeling efforts.

Full-Field Reservoir Characterization and Geocellular Modeling of the Kuparuk River Field, North Slope, Alaska

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Abstract

The Kuparuk River Field, located on the North Slope of Alaska, is the second largest oil field in the U.S. Discovered in 1969 with production beginning in 1981, the reservoir interval extends over 280 square miles and has a gross thickness of 300 ft. **STOOIP** is estimated to be 6 **BBO**, of which 2 **BBO** have been produced to date. The field is produced from approximately 1000 wells on 160 acre spacing from 44 drill sites, employing a north-south line drive with waterflood, and miscible **WAG** processes.

A major initiative has been undertaken to build a new full-field reservoir simulation model as a leveraging tool for managing the field performance. Key issues to be addressed using this model include **EOR** expansion to additional drill sites and field-wide evaluation of potential by-passed oil. In addition, this modeling work will support justification and planning of infill **CTD** (coil tubing drilling) and rotary wells.

To support this reservoir engineering effort, a full-field geocellular model has been constructed, integrating 20 years of field data and reservoir characterization work. The full-field model consists of 151 million total cells of which approximately 20 million active cells are in the fine scale model. The fine scale model has been up-scaled in preparation for full field compositional flow simulation which, in turn, may impact flood design, **EOR** adjustments, data acquisition strategies, and budgetary long range planning. Small sectors of the model are extracted to look at individual well patterns in more detail. Using such sector models enables the identification, planning, and execution of infill drilling opportunities.

Fault Compartmentalization of Stacked Sandstone Reservoirs in Growth-Faulted Subbasins: Oligocene Frio Formation, Red Fish Bay Area, South Texas

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Abstract

An integrated study using 3D seismic, wireline logs, and core analyses was conducted to establish strategies for exploring in compartmentalized, lowstand, prograding, deltaic systems. Frio sediments, averaging ~11,000 ft, are commercial gas reservoirs in several of the growth-faulted, intraslope subbasins in South Texas. These exploitation targets are typically located in fault-bounded compartments that form three- and four-way structural closure. However, understanding the stratigraphic component is crucial to successful exploitation of these sandstones.

The Frio third-order lowstand prograding wedge in Red Fish Bay Field is composed of 10 higher order, lowstand deltaic and superposed transgressive, depositional systems tracts. The sandstones are fine-grained, lithic arkoses having a mean porosity of 20% and tens of millidarcies of permeability. The main constituents of these sandstones are quartz, feldspar, and volcanic-rock fragments. Feldspars typically exhibit a substantial amount of secondary dissolution and micropores. Quartz cements, as well as interstitial clays, are minor. Porosity reduction occurs primarily by compaction.

Gravity failure along the upper slope generated syndepositional faults that displaced mobilized mud basinward of a growing lowstand sedimentary wedge. These growth faults trend generally northeast-southwest, setting up small subbasins. Associated with the growth faults are numerous subparallel, postdepositional synthetic faults. In addition, normal faults trend perpendicular to the growth faults, establishing a complex pattern of fault compartmentalization, which dissects the prograding-wedge depositional patterns. Pressure-decline analysis demonstrates compartmentalization that is due to (1) laterally discontinuous sandstone bodies and (2) fault-segregated sandstone bodies.

Reservoir Characterization of the Fullerton Clear Fork Field, Andrews County, Texas

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Abstract

This paper is a summary of the six-step methodology used to build a full-field reservoir model of the Fullerton Clear Fork Field in Andrews County, Texas. (1) Three Leonardian sequences and three high-frequency sequences are defined on the basis of vertical facies successions observed in core material and interpreted on cross sections. Studies of analog outcrops in the Apache Mountains, West Texas, are integrated into the interpretation to verify the stratigraphic architecture. (2) The sequences are subdivided into high-frequency cycles and flow layers suitable for distributing petrophysical properties and correlated to more than 1,000 wells. (3) Vertical profiles of porosity, permeability, and initial water saturation (Sw_i) are calculated from wireline logs using the rock-fabric approach. Because only gamma-ray and porosity logs were available, the stratigraphic framework was used to map the spatial distribution of rock fabrics. (4) The rock fabrics were converted to petrophysical class and, together with porosity from wireline logs, used in class-specific transforms to calculate permeability and Sw_i. (5) The full-field model was constructed by distributing the calculated petrophysical properties laterally within high-frequency cycles. The resulting patterns vary considerably from sequence to sequence. (6) A flow simulation model was then constructed in a portion of the field in a similar manner. Areas of upswept hydrocarbons were located by reconstructing field history and simulating production history.

Systematic Geological and Geophysical Characterization of a Deepwater Outcrop for "Reservoir" Simulation: Hollywood Quarry, Arkansas

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Abstract

A 3D geological model was constructed from a 3D quarry outcrop near Hollywood, Arkansas, for 'reservoir' flow simulation that can address the effects of small-scale ('subseismic') interwell heterogeneities on potential production problems in analog deepwater (and other) oil and gas reservoirs.

Dimensions of Hollywood Quarry are 380 x 250 x 25 m (1247 x 821 x 83 ft). The quarry exposes in 3D the upper Jackfork Group turbidites, which are often used as an outcrop analog for deep-water reservoirs in the Gulf of Mexico and elsewhere. The quarry is unique in that within its walls, numerous features can be examined which are typically found in subsurface reservoirs at larger scales, and which could dramatically affect reservoir performance.

Systematic characterization of this quarry was conducted in order to (A) simulate the effects of these features upon reservoir performance and (B) characterize them with instrumentation routinely used by reservoir geologists, geophysicists, and engineers. Techniques used to characterize the quarry include: photomosaic mapping, behind-outcrop coring and borehole image logging (**FMI**™), outcrop gamma-ray (**GR**) logging, measured stratigraphic sections, sequential photography of quarry walls, Digital Orthophoto-Quadrangle mapping (**DOQ**), Global Positioning System (**GPS**), including laser gun positioning of geologic features in 3D space, shallow high resolution (hammer) seismic reflection (**SHRS**), and Laser Imaging Detection and Ranging (**LiDAR**).

These combined techniques provided the basis for reconstructing the 3D geology within the quarry prior to its excavation. The resultant 3D geological model, constructed in **GoCad™**, includes spatially-oriented stratigraphic and structural features, and various up-scaling combinations. Results of fracture analysis were not included in the model, however, this analysis provided information on the orientation and origin of the fractures in relation to regional and local deformation. The model was imported into **Eclipse**™ and 101 combinations of geological features, drilling scenarios, and drive mechanisms were simulated for a 10 year 'production' period.

Results indicated that presence and absence of faults is a major factor when producing this analog "reservoir." Simulated production is reduced by 0.1 - 15% when faults are incorporated into the simplest "Tank" model. Partially sealing faults result in 1-10% less production than when faults are not sealing. A horizontal well across faults results in 4-21% higher production than with vertical wells.

The "Tank" model, provides 17% more oil in place (**OOIP**) and 12% more oil production than does more geologically realistic "reservoir" models. Adding geological information to the model, such as shale boundaries and faults, increases the accuracy of the initial volumetric calculations.

Stratigraphic and structural features within the 24 acres of geology reconstructed at Hollywood Quarry reveal horizontal and vertical complexities which could aid or hinder fluid flow in an analog reservoir at this, or larger scales. Systematic characterization of this quarry, and subsequent fluid flow simulation, has proven to be very useful in providing a better understanding of the geologic causes of various reservoir performance issues.

Outcrop Analog Study of Turbidites of the Miocene Whakataki Formation, New Zealand: Significance for Reservoir Volumetrics and Modelling

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Abstract

Thin-bedded turbidites are an important hydrocarbon reservoir facies worldwide. An example occurs in an exceptionally well exposed, laterally extensive shore platform outcrop of early Miocene Whakataki Formation, East Coast North Island, New Zealand. The most likely depositional setting is overbank, near base of slope.

The thin-bedded turbidites studied comprise approximately 360 sandstone beds interbedded with mudstone in a 32 m thick section. Beds show cyclicity in thickness with wavelengths of approximately 1 m and perhaps 14 m. Misleading estimates of net:gross can be made if cyclicity is ignored. Detailed study of a single bed comprising mainly **Tb-Tc** turbidite intervals indicates considerable variation at a decimeter and finer scale in porosity and permeability, both laterally and vertically within the bed. This suggests reservoir parameters derived from cores may not be reliable when extrapolated away from a well. An overall modeled average porosity of 14.5%, when combined with average net:gross of 74%, indicates bulk porosity for the unit of around 10%.

FMI image logs and the seismic character of gas-bearing thin beds drilled nearby in the offshore at Titihaoa-1 exploration well also show cyclicity of wavelength ~ 1 m and suggest the outcrop studied is a close analog, and hence, could provide a useful insight into likely reservoir architecture and characteristics at depth.

Outcrop Versus Seismic Architecture of Deep-Water Deposits: Use of LIDAR Along a Slope-to-Basin Transect of the Brushy Canyon Formation, West Texas

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Abstract

The stratigraphy of deep-water reservoirs is commonly interpreted using seismic data. Exploration-grade seismic data are typically acquired with peak frequencies varying from 30 to 60 Hz, resulting in an average vertical stratigraphic resolution of between ~23 m (30 Hz) to 11 m (60 Hz) in siliciclastic sediments. Many stratigraphic bodies, such as architectural elements and beds, can not be resolved at these frequencies, however. Seismic forward modeling of deep-water outcrop analogs provides a method by which this uncertainty can be addressed. Such modeling allows us to produce seismic images constructed from outcrops, where architectural elements, bedding, and facies are known. One of the advantages of this technique is the ability to bridge the gap between stratigraphic concepts learned from outcrop analogs and observations from seismic data sets.

Seismic forward models of five exposures from the Brushy Canyon Formation of west Texas are presented here. The exposures span an upper slope to basin-floor transect through the depositional system. Each outcrop contains unique stratal architecture and facies related to its position on the slope-to-basin physiographic profile. The seismic forward models have been constructed using geologic interpretations from LIDAR (light detection and ranging) data, stratigraphic columns, photo-panels, and paleocurrent measurements. These models are generated at several peak frequencies (30, 60, and 125 Hz). The resulting seismic forward models can be compared directly with corresponding outcrop analogs, allowing a direct comparison between outcrop and seismic architecture. The outcrop and seismic architecture of each of the five models can be compared with one another to address changes in seismic architecture associated with their positions on the slope-to-basin physiographic profile.

High Frequency Characterization of an Outcropping, Sinuous Leveed-Channel Complex, Dad Sandstone Member, Lewis Shale, Wyoming

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Abstract

This paper presents the results of data collection, analysis, and integration to build a 3D geologic model of an outcropping leveed-channel complex. Data is from more than 120 standard measured stratigraphic sections, behind-outcrop drilling/logging/coring, ground-penetrating radar and electromagnetic induction surveys, and 2D shallow seismic reflection acquisition.

This leveed-channel complex, which is part of the Dad Sandstone Member of the Cretaceous Lewis Shale, Wyoming, consists of ten channel-fill sandstones, confined within a master channel. The complex is 67m (200ft.) thick, 500m (1500ft.) wide, and has a net sand content of approximately 57 percent. Individual channel-fills are internally lithologically complex, but in a systematic manner which provides a means of predicting orientation and width of sinuosity. Although it has not been possible to completely document the three-dimensionality of this system, the 3D model that has evolved provides information on lithologic variability at scales which cannot be verified from conventional 3D seismic of subsurface analog reservoirs. This vertical and lateral variability can provide realistic lithologic input to reservoir performance prediction. An outcome of this study has been knowledge gained of the extent of manipulation required to obtain the spatially correct geometry and architecture of strata when integrating outcrop and shallow, behind-outcrop data sets.

Petrophysical Heterogeneity of a Pleistocene Oolitic Shoal: Lessons for Ancient Reservoirs

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Abstract

The shallow subsurface at Ocean Cay on western Great Bahama Bank consists of Pleistocene oolitic sand shoals and adjacent facies that exhibit facies-dependent petrophysical heterogeneity and reveal depositional and early diagenetic controls on petrophysical properties in oolitic bank margin reservoirs. Sedimentological heterogeneity is produced by complex facies architecture associated with abrupt lateral changes, while diagenetic heterogeneity is largely the result of patchy dissolution and cementation.

The investigated oolitic interval is the topmost unit in 22 tightly-spaced borings covering an area of about 1 km^2. Typical lithofacies include cross-bedded oolitic and oolitic/skeletal/peloidal fine- to coarse-grained grainstones and bioturbated skeletal/peloidal grainstone to packstone ranging in thickness from 0.5 m to 15 m. The architecture of the cross-bedded facies is similar to the modern Cat Cay shoal configuration of bars and superimposed sand waves that are linked to tidal flows. Particularly, the juxtaposition of bioturbated skeletal/peloidal sediment to cross-bedded oolitic/peloidal sands is mirrored in the Pleistocene section. Intense bioturbation within the skeletal/peloidal grainstone to packstone and bedding in the oolitic/peloidal/skeletal grainstone facies produce small-scale heterogeneity that is enhanced by diagenesis.

Petrophysical data and petrographic analysis show that, in addition to facies, diagenesis controls porosity and permeability at different intensities. In particular, permeability is very sensitive to cementation and can be drastically reduced by few rims of fibrous aragonite and/or meniscus cements. Porosity in the Ocean Cay grainstones is high, ranging from 29 to 47%, and permeability ranges from 0.1 to 11500 mD. Permeability is partly controlled by bedding. The average permeability in the massive-bedded oolitic grainstone lithofacies is 2770 mD while it is only 620 mD in the laminated and cross-bedded oolitic/peloidal grainstone lithofacies. Vertical/horizontal permeability ratio decreases with increasing bedding complexity: in massive bedded oolitic grainstone k_v/k_h 0.34, in oolitic/peloid laminated and low-angle cross-bedded grainstone k_v/k_h 0.22, and in trough and tabular cross-bedded oolitic/peloid grainstone k_v/k_h 0.11. The relationship between permeability and porosity can be approximated by power-law functions.

Values for the Archie cementation exponent range from 1.9 to 4.3 (m_{avg} = 2.7), and the cementation exponent generally increases with increasing depth. For Ocean Cay carbonates the influence of microporosity, which is as much as 35-55% of the pore volume in these rocks, on critical water saturation is significant. Critical water saturation ranges from 36% to 95% and decreases with increasing porosity. In general, petrophysical trends for some properties in the Ocean Cay oolitic/oomoldic rocks are consistent with extension of trends for lower porosity/permeability rocks in ancient reservoirs to higher porosity and permeability.

Spatial Trend Metrics of Ooid Shoal Complexes, Bahamas: Implications for Reservoir Characterization and Prediction

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Abstract

Although the general aspects of oolitic depositional systems are well-documented, their landscape-scale patterns (geobodies) are not well enough understood to offer quantitative, predictive insights for reservoir characterization. To begin to fill this basic gap in understanding, this study describes the morphology, hydrodynamics, and process sedimentology of several modern tidally dominated Bahamian ooid shoal complexes and compares the patterns with patterns in Kansas Pennsylvanian analogs. A companion paper explores linkages further, documenting petrophysical, geophysical, and production characteristics of these Pennsylvanian oolitic reservoirs.

Integrating remote sensing imagery with quantitative bathymetric, fluid flow, and granulometric data in a **GIS**, we document geomorphic and sedimentologic patterns and processes in several active tidally-dominated shoals. Results reveal that parabolic bars form a common morphologic motif, although there is considerable variation on that general theme. Different processes can lead to varying depositional geometries and sedimentologic patterns. Nonetheless, the landscape-scale configuration of bars and superimposed sand waves is linked closely to patterns of tidal flows. Bars are not homogenous bodies, however, and granulometric parameters such as sorting and mud percentage vary systematically and predictably within the hydro-geomorphic framework.

Through exploring modern oolitic shoals, this study provides new insights on details of their morphology and dynamics as well as links between geomorphic framework and grain size and sorting; some patterns are similar to those within geobodies in Pennsylvanian reservoir analogs. These insights provide quantitative predictive information on facies geometries, on grain characteristics, and depositional porosity in analogous ancient ooid shoals.

Multiscale 3D Static Modeling for Exploration and on Down the Lifecycle Stream

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Abstract

A hierarchical organization of heterogeneity in sedimentary systems has long been noted and this concept was explicitly built into Shell's proprietary reservoir modeling system in the early 1990's. The approach nested progressively finer levels of detail within parent objects and provided a mixed deterministic and stochastic technique for achieving realistic reservoir architectures at multiple levels in the hierarchy of heterogeneity. By 1999, the concept of hierarchical static modelling had been extended to basin-scale, as a means to promote consistency between local and regional data, interpretations, and models. Tangible business benefits were demonstrated for both exploration and appraisal decision making and the approach promoted continuity in subsurface evaluation along the whole exploration through to production lifecycle.

Key to the success of the multiscale static modeling approach is the combination of multiple data types (having differing resolutions and degrees of completeness) and global geological knowledge to complete the gaps associated with data resolution limits and incomplete data coverage. Synthetic seismic expression of resultant models is used to ensure consistency with available seismic information.

Event-Based Geostatistical Modeling: Application to Deep-Water Systems

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Abstract

Geostatistics is often used to build multiple models of reservoir geological heterogeneity for the probabilistic assessment of reservoir flow response. Current geostatistical algorithms, object-based or pixel-based, using semivariograms or training images, enable the reproduction of spatial statistics inferred from available conditioning data and analogs but rarely integrate information related to depositional processes. Indeed, because conventional geostatistical models are constructed without any concept of time or depositional sequence, their ability to incorporate sedimentological rules, which explain facies geobodies interactions and intra-body porosity/permeability heterogeneity, is quite limited. One consequence of such a limitation is that, unless spatial constraints tediously derived from alternative depositional interpretations are explicitly imposed to the simulation, conventional geostatistical methods only generate stationary statistical models that may not be representative of the full range of actual reservoir heterogeneity uncertainty.

Recently, the event-based approach has been introduced recently as a new branch of geostatistics, in which stochastic models are constructed as a sequence of depositional events. The sedimentological process is incorporated as a set of numerical rules that control architectural element geometry and the sequence of events through the occurrence of avulsion, meander migration, progradation, retrogradation, and aggradation. In addition, event-based models can be conditioned to sparse well data and soft data (seismic), typically available in deep-water systems.

The integration of sedimentological process into geostatistical modeling may provide a more geologically realistic representation of reservoir heterogeneity and help better assess reservoir flow response. Also, event-based geostatistics may be applied as a new framework to test distilled sedimentological rules and analyze their impact on reservoir heterogeneity.

Event-Based Models as a Quantitative Laboratory for Testing Quantitative Rules Associated with Deep-Water Distributary Lobes

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Abstract

Analysis of modern depositional systems, high-resolution seismic and outcrop data reveal a significant degree of complexity in the heterogeneity associated with deep water distributary lobes. These heterogeneities commonly have a significant influence on reservoir performance. This complexity is the result of variations in sand body architectures related to varying depositional and erosional processes. The translation of these processes into quantitative rules is a powerful exercise for the purpose of testing our understanding of depositional processes and hence forming predictive geologic models. Yet, the influence of coupled rules is difficult to assess *a priori* due to feedbacks and interference. A computationally efficient and intuitive quantitative framework is, therefore, a valuable means to explore potential rules and their associated interactions.

In the event-based framework, architectural elements are assigned to forward-simulated flow-event paths that obey simple geologic rules. The geologic rules qualitatively relate to sedimentary processes and constrain the geometry and location of architectural elements given the current state of the model for any time step. Rules may be coded to model allogenic and autogenic sedimentary processes such as avulsion, aggradation, progradation, retrogradation, and meander migration, along with the evolving influence of gradient and accommodation. Thus, event-based models can aid in the empirical testing of quantitative rules. This exercise leads to an improved quantitative understanding of process and the construction of more accurate geologic models that may better predict reservoir performance of these often economically challenging developments.

Beginning with the End in Mind: Exploration-Phase Reservoir Modeling of Multi-Story Channel/Levee Complexes, Deep-Water Nigeria

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Abstract

Geoscientists commonly employ high-quality three-dimensional seismic data to reduce deep-water prospect risk. For years, direct hydrocarbon Indicators (**DHIs**) have addressed hydrocarbon presence, however only more recently have images from three-dimensional datasets been employed to interpret the subsurface reservoir architecture of deep-water sinuous channel systems. Such architectural understanding, particularly in multi-story deep-water channel complexes, is key to predicting well count and spacing, thus ultimately prospect value.

By combining seismic profile channel interpretation, volume interpretation and analog studies, detailed geocellular models were created for offshore Nigeria isolated and stacked multi-story channel complexes. Gross rock volume was defined by interpreting the channel complex top and base horizons that define the reservoir 'container.' Seismic facies analysis was applied to amplitude extractions representative of interpreted discrete architectural zones within the reservoir container. In turn, interpreted facies maps were used for conditioning layers within the geocellular model. Dimensional information for facies objects was recorded from the three-dimensional seismic volume and from both subsurface and outcrop analogs. Individual facies objects were stochastically placed, heavily conditioned to seismic control, having an overall aim of replicating analog end members. The key identified uncertainties of net-to-gross and sand object connectivity were characterized quantitatively and qualitatively through the application of volume sculpting, opacity rendering, and multi-body detection techniques. Geocellular modeling-ranged results were assigned within the flow simulation process to condition well performance, and ultimately, risked pre-drill prospect value was calculated. Subsequent drilling of one of the modeled prospects provided calibration for the assumptions entered into the geocellular models, enhancing the value of the models as predictive tools for analogous leads/prospects.

Modeling, Upscaling and History Matching Thin, Irregularly-Shaped Flow Barriers: A Comprehensive Approach for Predicting Reservoir Connectivity

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Abstract

Accurate modeling of flow path connectivity is critical to reservoir flow performance prediction. Flow path connectivity is controlled by the complex shape, extent, and spatial relationships between pay intervals, their intersection with wells, and the existence of flow barriers between wells. This reservoir heterogeneity can be captured in a flow simulation model as facies patterns among cells and as effective properties within cells (porosity and permeability). However, fine-scale, irregularly-shaped flow barriers between cells can not be accurately represented with pixel-based modeling techniques.

To preserve these important fine-scale geological features at the flow simulation block scale, an additional modeling variable is introduced as the edge of a model cell. This cell edge is a continuous or categorical value associated with the cell face and is defined in conjunction with the cell centered property which is often reserved for facies types and/or petrophysical properties. An edge model is created that captures the facies and edge properties as a vector of information at each cell location. For the flow simulation model, the edge properties are easily translated into transmissibility multipliers.

Using the example of 3D shale-drapes attached to channel-sand bodies in a deep-water depositional setting, a methodology is presented in which these shale drapes are accurately up-scaled and history matched to production data while maintaining the geological concept that describes the drape geometry. The perturbation parameter in history matching is the continuity of the shales as an edge property.

More generally, this coupled modeling of cell-center and cell-edge allows for more flexible reservoir modeling, opening up the potential for modeling and history matching complex geological features effectively at the scale that they are relevant, without additional computational cost of flow simulation.

Integrated Reservoir Model of a Channelized Turbidite Reservoir: Geostatistical Geological Modeling Honoring a Quantitative 3D Seismic Constraint

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Abstract

A methodology has been developed which is devoted to the integration of seismic information within the geological stochastic modeling workflow. Its aim is to optimize the characterization of fine-scale internal heterogeneities of the reservoirs. This workflow consists of three steps:

- Lithoseismic interpretation and definition of a 3D seismic constraint,
- Reconciliation of seismic data with the geological model,
- Geostatistical geological modeling using a 3D seismic constraint

The result of the first step is a 3D volume of geological facies proportions at the seismic scale. It is described in detail in a separate companion paper.

The second step aims to improve the quantitative match of 3D seismic attributes computed directly from the detailed geological model. This implies first ensuring optimal coherency between well and seismic data. Secondly, distributions of acoustic parameters are determined for each geological facies using well log data. This information is used to obtain 3D synthetic cubes of seismic attributes, which are compared to real data. Finally, the 3D facies proportions are updated to minimize an objective function defined by the mismatch between real and synthetic seismic attributes.

In the third step, the non-stationary truncated Gaussian method is used to fill a fine grid geological model integrating a high resolution 3D seismic constraint and well information. The seismic constraint defines the main spatial trends of facies proportions, and the wells locally constrain facies in the model. This modeling process captures the geometry of complex geological objects and to reproduce the distributions of heterogeneities.

This methodology has been successfully applied to the Girassol Field. Comparisons between predicted and real impedance cubes clearly show the capability of the geological model to reproduce high-resolution seismic information. Some results of the geostatistical modeling are presented in this paper, as well as quality control tests and sensitivity analysis to critical parameters.

Impact of Volumetric and Connectivity Uncertainty on Reservoir Management Decisions: Case Study from the Humma Marrat Reservoir, Partitioned Neutral Zone

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Abstract

A two level design of experiments (**DoE**) workflow was used to evaluate the Humma Marrat reservoir in the Partitioned Neutral Zone (**PNZ**) between Saudi Arabia and Kuwait. The Jurassic-age Humma Marrat reservoir consists of productive limestone and dolomite intervals separated by very tight limestone and/or shaly limestone zones. The reservoir depth is about 9000 ft subsea and the gross reservoir interval is about 730 ft thick. The partially dolomitized lowermost interval (informally known as the Marrat E) is the most porous and permeable zone. The porosity within productive zones is 6-20% and permeability is generally < 20 md. Fracture-controlled production may be important in the uppermost zone (Marrat A). The middle Marrat C zone is very tight. Discovered in 1998, the reservoir currently produces from five wells. Additional delineation wells and production wells are planned for 2006 and 2007.

Reservoir uncertainties were assessed via finite difference dynamic simulation of earth models generated using parameter combinations specified by a Plackett-Burman **DoE** table. Cumulative oil production was used as the response variable in the **DoE**-based workflow. The first level **DoE** evaluated uncertainty sources related to reservoir volume and connectivity including structural uncertainty, facies distribution, porosity histogram, water saturation histogram, original oil/water contact, porosity semivariogram range, permeability multiplier, fault compartmentalization, and fault transmissibility. Only the porosity histogram uncertainty was determined to be statistically significant. The results from the first level **DoE** work were used to define earth models for the second level **DoE**, in which the following "dynamic" uncertainty sources were assessed: aquifer support, rock compressibility, extent of heavier oil, vertical to horizontal permeability ratio (kv/kh), **PI** multiplier, residual oil saturation (Sorw), and relative permeability (krw @ Sorw). The results of the second level **DoE** work showed that only the earth model and PI multiplier uncertainties were statistically significant. The results from the second level of the **DoE**-based workflow were used to generate the reservoir models for development optimization and economic analysis. The P_{50} model was used to screen development options that included well spacing, well type, and horizontal well length. Economic analyses were conducted to select the optimum development scenario using the P_{10}, P_{50}, and P_{90} reservoir models.

This paper focuses on the initial **DoE**-based evaluation of the Humma Marrat reservoir that was completed in mid-2004. The work illustrates the **DoE**-based approach to assess and model reservoir uncertainties. As significant additional data (*e.g.*, reprocessed 3D seismic, revised velocity model, additional **MDT** and **PLT** pressure data, and delineation wells) became available after the initial evaluation was complete, the **DoE** uncertainty tables and models were updated. Since this paper is a case history, reservoir evaluation work based on data acquired or re-interpreted since the fourth quarter of 2004 also is included, although only critical aspects of the post-2004 work are discussed in detail. A companion paper in this volume (Meddaugh and Griest, 2006) provides a historical assessment of OOIP uncertainty for the Humma Marrat reservoir from pre-drill through the end of 2005.

An Integrated Engineering-Geoscience Approach Leads to Increased Resource Capture from Carbonate Reservoirs

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Abstract

Pre-mature water breakthrough can be a common problem for carbonate reservoirs. The field concerned here has producing intervals from the Late Triassic Baldonnel Formation, dominantly by porous dolostone and limestone. Water was produced from some wells, raising a question whether this implied the end of field-life or was attributed to fractures or local high permeability streaks. A multidiscipline study involving geological, petrophysical, petrographical, geophysical, reservoir-engineering analysis, and field management provided an integrated solution to the problem. Structural grids based on 2D seismic mapping were tied with well picks. Detailed core and thin-section analyses allowed us to identify petrophysical facies and rock types, which were then linked to a sequence stratigraphic framework. A geocellular model was constructed to delineate 3D variation of petrophysical properties. It was difficult to quantify the original gas-water contact (**GWC**) using log data alone due to the presence of bitumen in the non-reservoir zones. Therefore, pressure data were analyzed to derive **P/Z** plots and obtain original reserves in place. The result of **P/Z** analysis agrees with the geological model, suggesting that the original **GWC** was at 775 meters subsea. By modeling the remaining reserve based on step-wise variations of current GWC and comparing the result of decline curve analysis, the current **GWC** was identified at between 758 and 762 meters subsea, giving a remaining reserve of 89 **BCF** (70% recoverable). This study resulted in a higher degree of confidence in resource capture, leading to a better strategy for field management and development.

An Integrated Geostatistical Approach: Constructing 3D Modeling and Simulation of St. Louis Carbonate Reservoir Systems, Archer Field, Southwest Kansas

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Abstract

Many essential aspects are involved in quantitative characterization of oolite carbonate reservoirs. Rock-facies classification, external facies geometry, and internal rock-property distribution are fundamental to characterization for reservoir simulation and prediction of future hydrocarbon recovery. The typical challenge for small Midcontinent fields in the U.S is absence of high-resolution seismic data capable of resolving relatively thin reservoir intervals. An integrated geostatistical approach is presented that uses available well data from the St. Louis Limestone in the Archer Field, southwestern Kansas, to improve oolitic reservoir modeling and corresponding streamline simulation. The proposed approach uses neural network and stochastic methods to integrate different types of data (core, log, stratigraphic horizons, and production); at different scales (vertical, horizontal, fine-scale core data, coarse-scale well-log data); and variable degrees of quantification (facies, log, well data).

The results include:

1. three-dimensional stochastic simulations of facies distribution of St. Louis oolitic reservoirs;
2. improved reservoir framework models (lithofacies) for carbonate shoal reservoirs;
3. increased understanding of spatial distribution and variability of petrophysical parameters within carbonate shoal reservoirs;
4. quantified measures of flow-unit connectivity;
5. 3D visualization of the St. Louis carbonate reservoir systems;
6. streamline simulations of the static geostatistical models to rank and determine the efficacy of the geological modeling procedure; and
7. better understanding of key factors that control the facies distribution and the production of hydrocarbons within carbonate shoal reservoir systems. Geostatistical 3D modeling methods are applicable to other complex carbonate oolitic reservoirs or siliciclastic reservoirs in shallow-marine settings.

Petrophysical Data Integration for Improved Reservoir Description

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Abstract

Integrated reservoir characterization relies increasingly on vastly improved log-based results from new technologies such as Nuclear Magnetic Resonance, **NMR**. Our experimental study is designed to extract more petrophysical information from **NMR** for reservoir characterization.

We compared the empirical permeability estimation based on **NMR** with direct measurements; evaluated the use of **NMR** observations in providing capillary pressure estimates; and the use of NMR to classify rock types. Using a 2MHz **NMR** spectrometer, we analyzed 90 clastic cores from five different wells. Cores were measured at 100% brine saturated and at irreducible saturation achieved through centrifuging the core plugs at 5800 rpm. High pressure mercury injection was performed on parallel samples from the same plug. The porosity of the cores studied ranged from 4% to 23% while measured permeabilities ranged from 0.01 md to 900 md.

The measured T_2 cutoffs (*i.e.*, the boundary between free and bound water) ranged from 6 ms to 100 ms, which represents significant departures from the typically assumed 33 ms cutoff for clastics. Mineralogy appears to have an influence on the T_2 cutoff value. In general the permeability estimation based on the weighted geometric mean of the T_2 time is better than the model based on the ratio of free fluid index to bound volume index. Additionally, mapping **NMR** and mercury measurements provided estimates of surface relaxivities, which ranged from 16 to 50 μm/sec.

Measurements of surface relaxivity allow the empirical mapping of **NMR** data to capillary pressure data. The mismatch between the cumulative **NMR** and mercury data at lower and higher T_2 times reflects differences in how the pore space is accessed between the **NMR** and the Hg measurements. The applicability of **NMR** T_2 distribution for rock typing is discussed. It is observed that **NMR** is more sensitive to subtle pore characteristics (dimension, shape, and composition, *etc.*) as compared to Levertt J-function derived from capillary pressure and may provide an alternative method for rock typing.

The Evolution of Reservoir Geochemistry

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Abstract

Reservoir geochemistry evolved during the late 1980s and early 1990s during one of the many downturns in exploration activity. A landmark paper in 1989 by William England of BP was one of the primary catalysts for the emergence of geochemistry as a tool for reservoir characterization. Among the many concepts appearing in that paper was the idea that compartments within a reservoir could be distinguished through the use of geochemical maturity parameters since oil in the different compartments had been generated at different levels of source rock maturity. At the same time, the geochemists at Chevron were utilizing high resolution gas chromatography of crude oils to demonstrate whether or not oils in different fault blocks or compartments were in communication. The increase in interest in applying geochemistry to reservoir characterization was manifested by numerous papers using many different techniques and concepts applied to a variety of reservoir problems. Many of these ideas quickly fell by the wayside but those that had real application were well received in the industry and are still in widespread use today.

Not all of these techniques are necessarily connected with communication between fault blocks but may cover topics such as wax accumulation; asphaltene precipitation; biodegradation; effects of water washing; and numerous other problems. It is also important to remember that geochemistry can be applied to characterization of gas reservoirs as well as oil reservoirs. In the same way as oil reservoirs, continuity and compartmentalization in gas reservoirs are two areas where geochemistry can play a key role. With gas samples, this is typically done through a combination of carbon and hydrogen stable isotopes. The development of the combined gas chromatograph–isotope ratio mass spectrometer now permits one to determine the isotopic composition of individual compounds, and as a result, it is a relatively facile process to determine the isotopic composition of the individual compounds in a natural gas sample. The purpose of this paper is to review the developments in reservoir geochemistry over the past two decades and to highlight this with examples of where geochemistry has been used successfully as one tool to address reservoir problems.

Geoscientific Workflow Process in Drilling a Deep-Water Well, Offshore Morocco

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Abstract

Analysis for placement of a well in deep water typically begins with a thorough study of the seafloor. This is followed by a shallow geohazard report, which is used to identify zones of instability in the shallow subsurface (faulting, over-pressured zones, *etc.*).

An example from a 415.55 km^2 (160.44 mi^2) 3D seismic survey, offshore Morocco, is presented. Amplitude extraction and stratal slice maps were generated within the focus area of the Ras Tafelney 3D seismic data-set volume. Three horizons have been mapped in the subsurface to track reflection events that showed bright positive amplitudes. In the survey area, the main potential hazards appear to be active sediment pathways (gullies) and shallow sands, both of which can be the site for shallow water-flow conditions. Minor faulting is present through different stratigraphic intervals but is relatively insignificant and therefore not considered to be a potential geohazard.

Gullies and canyons are the most prominent features in the study area. They include active modern sediment pathways, which may be subject to slumps and slides and therefore may negatively impact nearby seabed structures. Older groups of buried channels that may be sand prone and/or associated with pore pressure anomalies were also mapped.

Sand-rich facies in the near seafloor sediment column are not in themselves hazards but should be characterized because of the potential for problems related to setting casing points. Sandy facies are also host to shallow water-flow conditions, shallow gas reservoirs, and hydrates.

Improvements in estimating drilling risk and costs that could be carried out include the analysis of offset logs, velocity data, sediment properties, and pressure data. In concert with the existing seismic data, these data can be used to create pore pressure cross sections and other displays that may reduce drilling risk and costs.

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