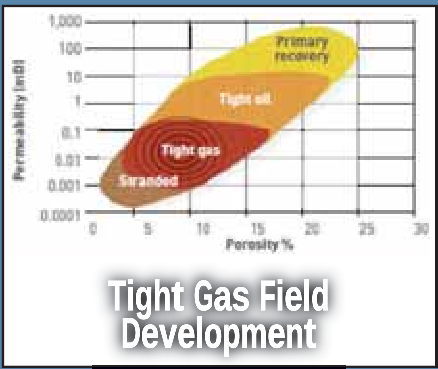
Brazil Oil & Gas, tt_nrg and Norway Oil & Gas

EPRASHEED
signature series

2010 – Issue 13

Saudi Arabia oil & gas

www.saudiarabiaoilandgas.com

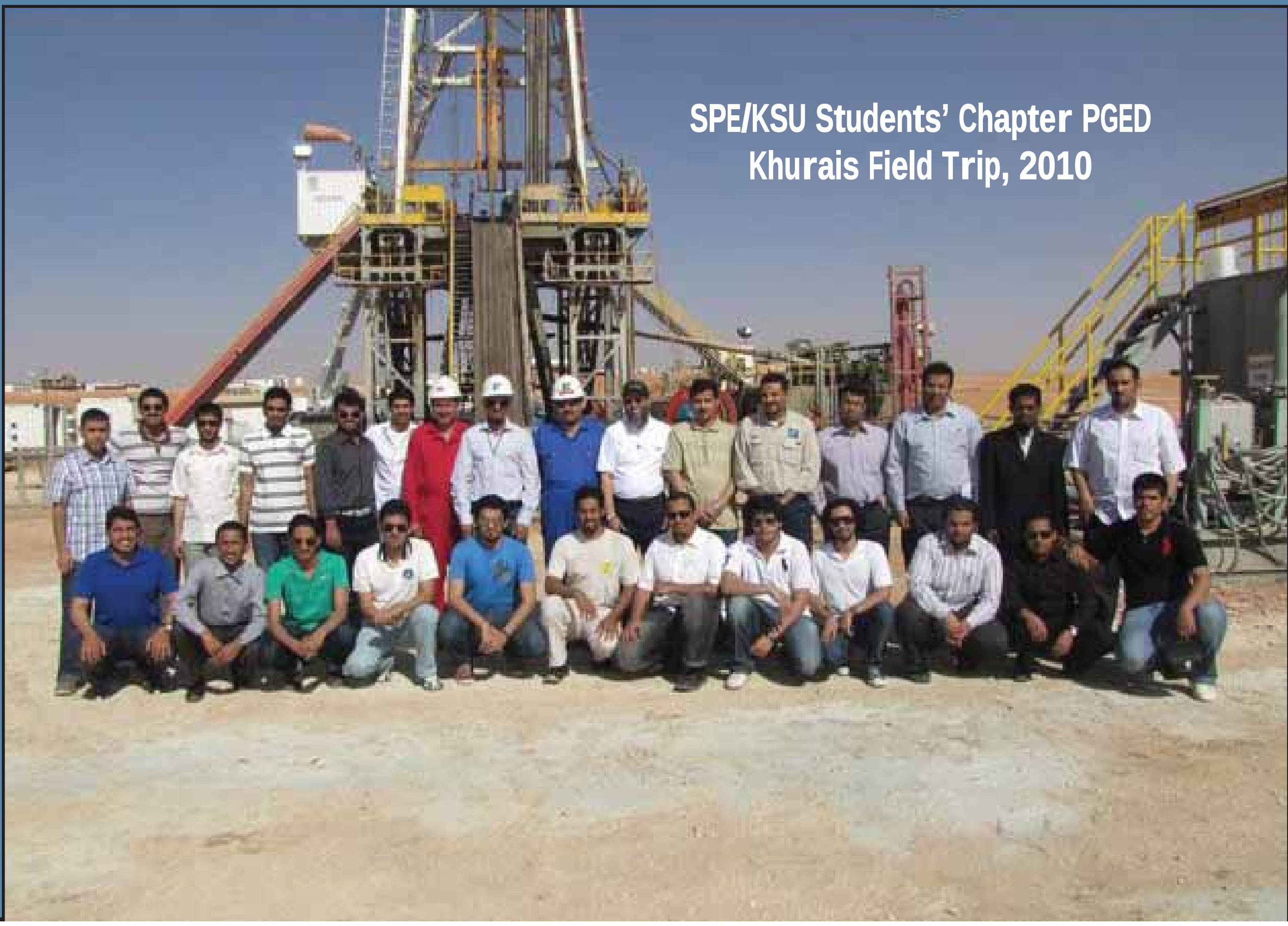


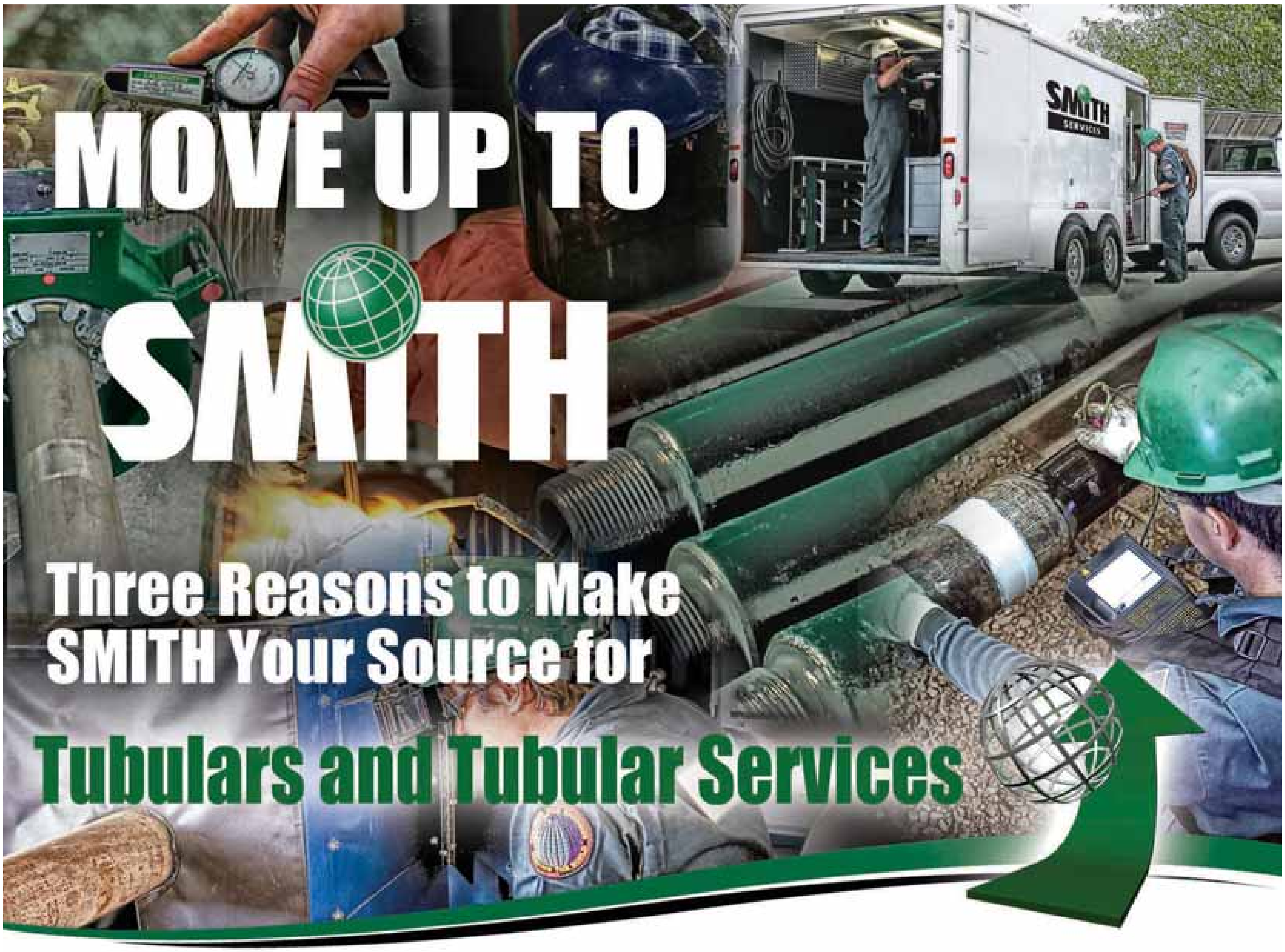
Tight Gas Field Development

New Oilfield Facility


Longest Cemented Liner

OFFICIAL PUBLICATION SPE/DGS Annual Symposium 2010


SPE/KSU Students' Chapter PGED
Khurais Field Trip, 2010



SMITH Means Superior Tubular Solutions

#1 A History of Excellence

For over 50 years the SMITH name and the Drilco® brand have been synonymous with excellence in tubular products and services. From the invention of Hevi-Wate™ drill pipe to the first use of continuous line heat treating for drill collar bars, to the comprehensive maintenance and repair facilities for BHA and down hole tools, SMITH has been continuously at the forefront of tubular sales and service.

#2 Extensive Product Range and Expertise

SMITH offers a full range of new tubulars including drill pipe, Hevi-Wate™, drill collars and kellys to optimize your drilling operations. SMITH also provides rental of these BHA products to reduce your overall inventory costs. In addition to our expert machine ship services, SMITH provides a full range of inspection and maintenance services for your drilling tools, including our new state-of-the-art mobile field hardbanding units which extend the life of your existing equipment inventory.

#3 Global Reach

SMITH has the worldwide infrastructure to support your operations no matter where you drill. With inventory and machine shop facilities strategically located around the globe, SMITH can be counted on to provide fast, dependable response to all your needs – 24 hours a day, 7 days a week.

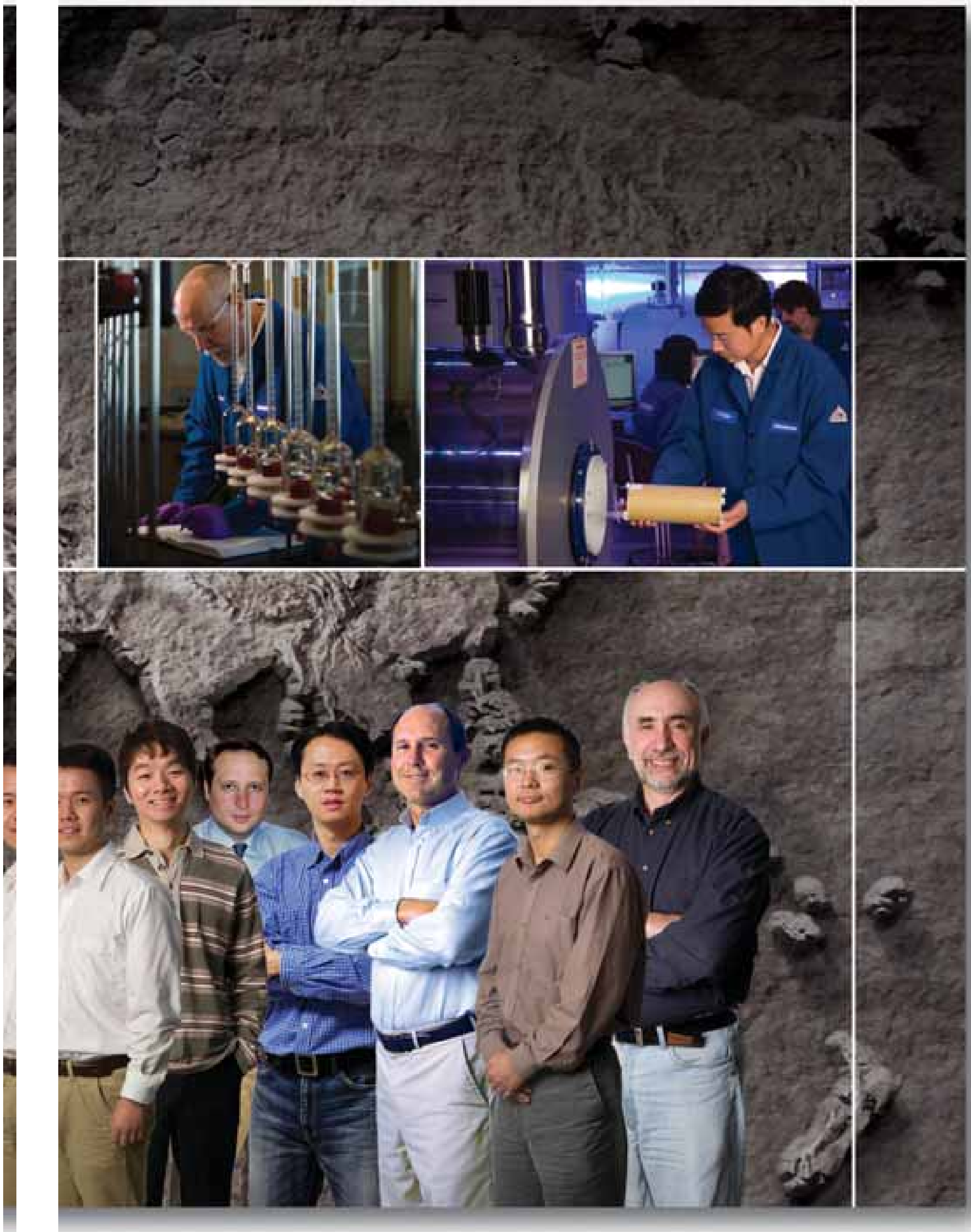
Call your Smith representative today for
superior tubular solutions you can trust.

www.smith.com

THE POSSIBILITIES ARE ENDLESS

SMITH


Need rock-solid formation evaluation service?
Meet the advisors



Carbonate Advisor

Schlumberger

2010 – Issue 13

Saudi Arabia oil & gas

EPRASHEED

signature series

www.saudiarabiaoilandgas.com

Contents

NEW FACILITY OPENING 8

By Baker Hughes Staff

WELCOME MESSAGE FROM THE CHAIRMAN, 2010 SPE/DGS ANNUAL TECHNICAL SYMPOSIUM & EXHIBITION 9

Faisal N. Al-Nughaimish

THE PETROCHEMICAL INDUSTRY: STRENGTHENING THE SAUDI AND GULF ECONOMIES 10

HE Ali I. Al-Naimi, Minister of Petroleum and Mineral Resources Kingdom of Saudi Arabia

OVERVIEW OF TIGHT GAS FIELD DEVELOPMENT IN THE MIDDLE EAST AND NORTH AFRICA REGION 15

By Ahmed Shehata, AUC/TPS, Ahmed Aly, AUC/Schlumberger and Lee Ramsey, Schlumberger TGCOE

TECHNOLOGY AND TEAM-BASED APPROACH YIELDS SAUDI ARABIA'S LONGEST FULLY CEMENTED HORIZONTAL LINER 22

By Marlio Campos Ramos/Saudi Aramco, Sameh Hussein and Kirby Wedewer/Baker Hughes Inc, Ansgar Dieker BJ Services Arabia Ltd.

A NEW NEAR-BIT AZIMUTHAL GAMMA-RAY TOOL FOR GEOSTEERING AND GEOSTOPPING APPLICATIONS 33

By Y. Al-Ansari, S. Abu Faizal, Baker Hughes

PREDICTION OF POISSON'S RATIO AND YOUNG'S MODULUS PARAMETERS FOR HYDROCARBON RESERVOIRS USING ARTIFICIAL NEURAL NETWORKS 41

By Bandar Duraya Al-Anazi, King Abdulaziz City for Science and Technology, Oil and Gas Center, Mohsen Saemi, Research Institute of Petroleum Industry (RIPI), and Ammal Al-Anazi, Saudi Aramco

WELLSITE GEOCHEMICAL ANALYSIS SPEEDS DECISION-MAKING WITH NEAR-REAL-TIME DATA 51

By Weatherford International Ltd Staff

THE USE OF THE INDUSTRY'S FIRST 3-D MECHANICAL CALIPER IMAGE WHILE DRILLING LEADS TO OPTIMISED ROTARY-STEERABLE ASSEMBLIES 55

By Junichi Sugiura, SPE, and Steve Jones, SPE, PathFinder Energy Services

MESSAGE FROM THE 2010 SPE PRESIDENT 65

Dr. Behrooz Fattahi

2010 SPE/DGS TECHNICAL SYMPOSIUM & EXHIBITION 66

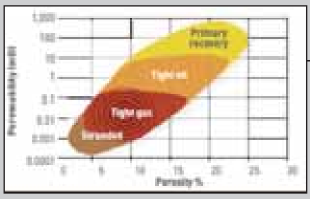
SPE/KSU STUDENTS' CHAPTER PGED KHURAIS FIELD TRIP, 2010 78

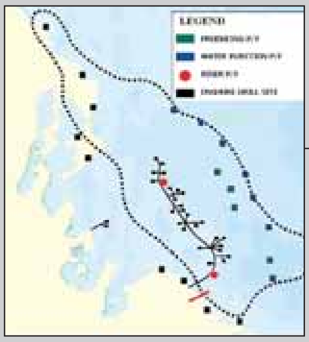
PROPERTIES, PLAYERS AND PROCESSES 80

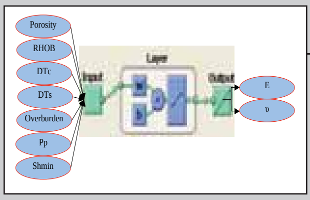
An extract from The Hydrocarbon Highway, by Wajid Rasheed

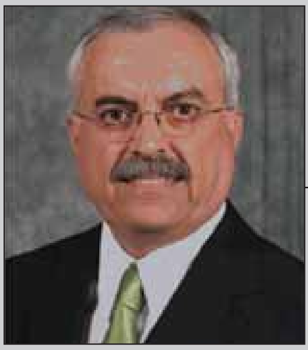
OGEP 2010 92

EDITORIAL CALENDAR, 2010 99









CEO and Founder EPRasheed

Wajid Rasheed
wajid.rasheed@eprasheed.com

Editors

JC Cunha (Technology)
Majid Rasheed
Mauro Martins

Design

Sue Smith

Contacts

United Kingdom

- Head Office
Tel: (44) 207 193 1602
- Brian Passey
brian@bspmedia.com
- Sally Cole
sally@bspmedia.com

Saudi Arabia

- Akram ul Haq
PO BOX 3260, Jeddah 21471
akram.ul.haq@saudiarabiaoilandgas.com
Tel: (966) 557 276 426
- Mohanned AlSagri
mohanned.alsagri@saudiarabiaoilandgas.com

Houston

- David Jones
david.jones@eprasheed.com
Tel: (1) 281 793 4314
- William Bart Goforth
william.goforth@eprasheed.com
Tel: (1) 713 304 6119

Brazil

- Ana Felix
afelix@braziloilandgas.com
Tel: (55) 21 9714 8690
- Fabio Jones
fabio.jones@braziloilandgas.com
Tel: (55) 21 9392 7821
- Roberto S. Zangrando
rzangrando@braziloilandgas.com
Tel: (55) 22 8818 8507

Baker Hughes: Expanding Oilfield Facilities

By Baker Hughes Staff

In 2010, Baker Hughes will inaugurate two major operations centers in Saudi Arabia, significantly expanding its capacity to service Middle East operating companies.

The 100,000+ square meter facility in Dammam, Saudi Arabia, brings together laboratories, offices, and repair & maintenance facilities for our operations. The location is home to a BEACON center – where Baker Hughes experts can remotely operate and monitor BHI operations.

In 2011, Baker Hughes will again expand its Saudi footprint. Construction has begun on the $10 million (US) Dhahran Research & Technology Center in Saudi Arabia. The center will combine Baker Hughes, Saudi Aramco and KFUPM University research capabilities to develop application-specific technologies for complex reservoirs, including the tight gas plays of Saudi Arabia.

The remote operations BEACON center.

WELCOME MESSAGE FROM THE CHAIRMAN, 2010 SPE/DGS ANNUAL TECHNICAL SYMPOSIUM & EXHIBITION

Dear Colleagues,

It gives me great pleasure to welcome you to the 2010 SPE/DGS Annual Technical Symposium and Exhibition, the first to be organized jointly by the Society of Petroleum Engineers (SPE) Saudi Arabia Section and Dhahran Geoscience Society (DGS).

The theme this year is "The Race to Ultimate Recovery: People, Technology, and Beyond". It is a call on technical experts from all disciplines to join forces and make the best out of our resources; it is a call for more, in an industry where every little counts.

The international and local response to the call for papers this year was beyond expectations. After a thorough review, the technical committee has endeavoured to bring the best concepts and case histories to the 2010 SPE/DGS ATS&E with an aim to share the best practices that have been adopted in various parts of the world.

With 17 technical sessions, panel discussion, poster sessions, pre-event courses and field trips, and exhibition, the 2010 SPE/DGS ATS&E offers one of its richest programs over more than 25 years of history, complemented by recognized keynote and invited speakers.

On behalf of the Program Committee, I would like to thank you for your support and commitment in making the 2010 SPE/DGS Annual Technical Symposium and Exhibition a grand success. I am sure you will find it a rewarding experience. Thanks also to Saudi Arabia Oil and Gas Magazine for their publication.

Sincerely,

Faisal N. Al-Nughaimish, Chairman

2010 SPE/DGS Annual Technical Symposium& Exhibition

The Petrochemical Industry: Strengthening the Saudi and Gulf Economies

Fourth Annual Forum

Ali I. Al-Naimi, Minister of Petroleum and Mineral Resources Kingdom of Saudi Arabia

Dubai, UAE, December 09, 2009

'Ladies and gentlemen, I would like to thank Engineer Mohamed Al-Mady, the association chairman, and Dr. Abdulwahab Al-Sadoun, the secretary general, for their invitation to speak to this Gulf Petrochemicals and Chemicals Association Forum. The growth of the association after only four years of existence, and the size of this annual gathering, are tributes to the leadership of GPCA. Let me also thank *Chemical Week* magazine for its co-sponsorship of the Forum. The presence of so many industry leaders from every continent is testimony to the region's rise as a global hub for the chemical industry.

While the backdrop of our meeting necessarily includes the world's anxieties concerning current financial strains here, I want to emphasize that the overall economy of the Gulf region as a whole remains strong.

Without question, the soundness and growing diversification of our regional economy will help restore calm following the turbulence of the moment. Of course, one of the fundamentals of our region's economic strength is the industry convened here for this forum – petrochemicals and chemicals.

The various topics that will be discussed at the forum in the coming two days are matters of concern to GPCA members and the chemical industry at large: sustaining success through consistent strategy, managing costs, securing access to competitive feedstock, to name a few.

What I hope to do in the next few minutes is to pose some points for you to reflect upon as the conference unfolds and challenge you to think about the longer term, rather than just focusing on next quarter's profitability. I will ask your indulgence kindly to allow me to use a few Saudi Arabian examples throughout this speech due to obvious reasons. But my hope is that this speech will set the stage for all of us to get the most out of our brief time together as possible. So I plan to focus today on three main topics:

First, it is always useful to think about where the industry has been as we think about where the industry might go in the future. We are in a world where changes happen more rapidly than ever before. Industry evolution should not be the exception, but in fact the expectation.

Second, I will talk about the general picture today and going forward from the view of an oil and gas producer. Chemicals are a significant and growing portion of the global petroleum industry, but as we all know the petroleum industry is very broad and strategic not only to companies, but also to countries.

And lastly, I want to talk about the future in terms of how we can cooperate and collaborate with one another towards a greater good for both the region and the world and for the betterment of this great industry.

In terms of historical growth, it is well documented that our region has attracted investment in the chemicals industry because of our sustainable competitive advantages. These advantages include not only a reliable, affordable supply of feedstock but also location and port facilities convenient to serve Asian and European markets. Additionally we have the advantages of the regulatory and political stability in the Gulf and good relationships with partners who helped us build our own competencies over the years. As a result, our region today boasts some of the largest and most efficient, modern facilities in the world after starting from very modest means in the late 1970s.

From the earliest days of petroleum production in Saudi Arabia until as recently as the 1970s, much of the gas that was brought to the surface with oil was flared. This same situation existed throughout the Gulf. In our case, the decision to end gas flaring and transform the gas from a wasted commodity to a useful resource involved taking a long strategic view.

The first piece of the strategy was actually to collect the gas and connect the Kingdom from the oil fields in our Eastern Province to potential users as far away as the west coast through creation of the Saudi Master Gas System, which took place in the 1970s. Saudi Arabia confounded the short-sighted by undertaking a strategic, long-term investment in a massive project to utilize hydrocarbon production capacity. This system has given us access to resources used for electric power generation, energy for water desalinization plants, and abundant, competitively priced feedstock for petrochemicals.

The industrialization saga continued with investment in what observers at the time called the biggest construction project in all of history – the creation of the modern industrial cities of Jubail on the East Coast and Yanbu' on the Red Sea shore. A special Royal Commission was established to build the infrastructure for the two cities.

Finally, in 1976, Saudi Arabia created the Saudi Basic Industries Corporation, or SABIC. SABIC, which Engineer Al-Mady so ably leads today, was assigned to initially develop the primary industries in the Royal Commission cities. With SABIC and its partners, the Kingdom moved definitively into using gas associated with oil production to manufacture value-added materials such as fertilizers and petrochemicals.

At the beginning of the 1980s, direct investment in the Saudi chemical industry was about $2 billion dollars. The goal at the time was simple – just to enter into the chemicals business. By the end of the 1990s, such investment had increased to approximately $20 billion and the goals of the industry began to change, from merely learning the business to operating in a self-sufficient manner.

Today SABIC continues to grow and prosper as an industry leader. Thirty percent of the shares of SABIC are owned by private and institutional shareholders in GCC countries. SABIC continues to leverage its strengths in numerous domestic and international joint ventures. Saudi Arabia now also has many private players in the chemicals industry, making a dynamic contribution to the market and to this association. In addition to SABIC, 13 other chemical companies are listed on the Saudi Tadawul Stock Exchange. From a single petrochemical mega-complex in 1983, the nation now has 24 mega-complexes, 14 of which are international joint ventures and several others are either under construction or planned.

Saudi Arabia today accounts for about 62 percent of chemical production in the GCC region and approximately 8 percent of global production. Saudi Arabia is already the world's largest methanol producer and the second largest ethylene producer. By 2015 the Kingdom's petrochemical production is projected to increase from today's levels of about 60 million tons per year to more than 80 million tons per year. The evolution of downstream industries is accelerating – moving beyond even the most sophisticated physical products toward sustainable leadership in human capital and advanced research. And industry analysts project that direct investment in the Saudi chemical industry by 2015 will far surpass the 100 billion dollar mark.

This is quite remarkable when put into context, but we have seen growth stories in the chemicals sector occur throughout the Gulf, with each country charting its own way forward. Taken as an entirety, GCC chemicals production appears set to move to greater and greater heights. The goals of the business are changing as well. The chemical industry in the Gulf is no longer simply operating facilities to manufacture products; it is becoming a key enabler of other industrialization activities.

But before we talk about shaping the future, we should spend a few minutes to focus on an area of the business which, like chemicals, touches our lives every day: the upstream oil and gas sector. The upstream industry is based on a declining resource model. In other words, the early days of an oil and gas field are often its best days from a financial point of view. This may be counterintuitive for those in the chemical industries who, after a start up period, expect to operate facilities for several decades and require relatively modest capital investment to maintain or debottleneck facilities.

A major change that has taken place during the past few years is that the Saudi Arabian Ministry of Petroleum and Mineral Resources has begun to take a more vital, strategic role in allocating feedstock to diversify and strengthen the Kingdom's economy.

In Saudi Arabia, we are blessed with abundant natural resources, and we were able to overcome challenges and provide competitively priced gas and NGL products fostering strong growth in our chemical industry. During the past 15 years, we have been able to add massive new investments in Hawiyah and Haradh, as well as our new gas development at Karan and our new ethane straddle plant. Besides a record number of wells being drilled by Saudi Aramco directed at new hydrocarbon sources today, we also have opened up exploration for new gas in the southern part of the Kingdom through our foreign partnerships with Shell, Sinopec, Lukoil and ENI.

Stewardship of our natural gas resources is a strategic strength for my nation and for our region and beyond. A program that began not too many years ago, based only on making productive use of associated gas that would have been flared, today has been transformed dramatically, for the economic benefit of the entire world. Even as we have produced vast amounts of natural gas, our production and reserves continue to increase.

In 1990, Saudi Arabia's natural gas reserves were 181 Trillion Cubic Feet (TCF). At year end 2008 they were higher, at 263 TCF, and we project that in 2010 proven reserves will be still even higher, as Saudi Aramco targets discovering a minimum of 5 TCF of additional non-associated gas reserves annually. Investment and application of new technologies are leading to greater abundance of natural gas. Another important factor is the change in the ratio of non-associated to associated gas. For instance in 1990, 75 percent of our natural gas reserves were in associated gas, whose production can be constrained by the factors of oil production. Today non-associated gas accounts for 48 percent of total gas reserves, and we expect it to constitute a significantly higher proportion in the future.

There is comparable good news in gas production. In 1981, Saudi raw gas production was 1,654 million standard cubic feet per day (MMSCFD). Today it is approximately 8,800 MMSCFD, and we project production levels to exceed 13,000 MMSCFD by 2020.

This means our investment and management strategies are succeeding in meeting our objective of always staying ahead of demand for natural gas – toward all of its end uses in power generation, desalinization, and chemical feedstock.

We see the future of the chemical industry evolving so that local producers foster further investment and creation of knowledge in many different sectors. I can offer a few observations about the future situation from a Saudi Arabian viewpoint. Our own national approach involves linkages between refining and chemical industries both inside and outside the Kingdom.

On November 8, 2009, Saudi Arabia celebrated the inauguration of Petro Rabigh, the largest integrated refining and petrochemical complex ever built at a single time. This $10 billion facility will be producing more than 18 million tons of petroleum-based products per year, with some two-and-a-half million tons per annum of ethylene and propylene-based derivatives. Petro Rabigh is jointly owned by Saudi Aramco, Sumitomo Chemical Company of Japan, and private and institutional shareholders who acquired equity in the company in 2007 in the first Initial Public Offering involving Saudi Aramco.

Saudi Aramco this year has also inaugurated another significant international joint venture in chemicals – the Fujian Refining and Petrochemical Company, in partnership with Sinopec of China and ExxonMobil. This enterprise, in Fujian Province, expands a refinery's capacity and adds new petrochemical facilities. The new petrochemical complex includes an 800,000 tons-per-year ethylene steam cracker, an 800,000 tons-per-year polyethylene unit, a 400,000 tons-per-year polypropylene unit and a 700,000 tons-per-year paraxylene unit.

Back at home and in the near future, Saudi Aramco is developing major integrated refinery-based chemical complexes through joint ventures with Dow Chemical in Ras Tanura, with Total in Jubail, and with ConocoPhillips in Yanbu. In addition, the Jazan refinery which is up for competitive bidding provides opportunities for petrochemical synergies.

In the coming years, Saudi Arabia is poised for increases in the quantity and quality of our exports. We will diversify our chemical portfolio into more complex, distinctive products such as specialty chemicals and engineering thermoplastics. Saudi Arabia now actively encourages private investment in the chemical sector in order to strengthen our position as a global chemical leader and to diversify towards value-added specialty chemicals, formulated products, and performance polymers.

Other opportunities will be found with various SABIC projects and Petro Rabigh Phase II, and other private sector projects are all working to develop projects with higher know-how content which will add to the technology profile of the industry and the utilization of novel, proprietary processes. Our aim is to be able to produce a substantial number of upstream products as well as a range of sophisticated downstream products for the development of the local market and the world market.

In connection with this, the Government of Saudi Arabia has initiated the Saudi Industrial Clusters Program to develop and to provide support to a range of new industries. The program aims to grow and diversify the national economy by developing targeted industrial sectors that leverage the Kingdom's natural resources, including the petrochemical industry products, and our young and growing Saudi workforce.

The sectors have been selected in areas where the Saudi Arabian fundamentals of abundant, competitive energy and basic materials can be leveraged to create competitive ventures that meet the aspirations of both the nation and the investor. The selections have been made only in sectors where we believe that over time Saudi Arabia can become competitive on a global basis. Key sectors now are being developed, each representing a different category of manufactured products: automotive value chain, metals processing, plastics, consumer goods, and solar. As you can see, the clusters program will create not only manufacturing industries but also spur additional development in the utilization of our mineral resources. Our goal is for global and regional markets to contain not just basic products but also a significant number of consumer and industrial products labeled "Made in Saudi Arabia."

The Saudi chemical industry leadership is intimately connected with our vision for economic and social development beyond physical products. Last September the nation inaugurated a remarkable new post-graduate research institution, King Abdullah University for Science and Technology, or KAUST. The university has enlisted numerous major corporate research partners – including Schlumberger, Boeing, Halliburton, and Dow Chemical as well as SABIC and Saudi Aramco.

The launch of KAUST accelerates efforts that have been going on for some time through higher education and specialized training to enhance the quality and quantity of opportunities for employment and economic growth in Saudi Arabia. King Fahd University of Petroleum and Minerals – enjoying strong partnerships with industry is internationally known for its excellence. Numerous other Saudi universities have endowed professorships and programs in partnership with the hydrocarbons and chemical industries. Specialized training institutions also support our strategy, as do the research and training centers of leading corporations operating in the Kingdom. Advances emerging from KAUST and other institutions will complement gains in intellectual property we expect from joint ventures of Saudi and international companies

Realizing our nation's strategic advantages as a global chemical hub – and reaching our further goals for development of intellectual and human capital – are vital to the citizens of Saudi Arabia. Our population is very young and is growing. This reality requires a high quality of education for our youth to support diversification of industries and the economy, and to provide jobs for the new generation.

Ladies and gentlemen, let me emphasize the need for action to promote international trade.

Petrochemical producers in the Gulf region export significant volumes of their products to other regions of the world – in fact to more than 100 countries. It is very important for our industry to have access to the world's market unfettered by artificial trade barriers. There is a concern that de-globalization is a growing threat and could result in restrictions of world trade.

Most experts are in agreement that growth in global trade is beneficial to economic growth in most countries. Growth in global trade in prior years has been credited with lifting millions of people out of poverty in the emerging economies and bringing lower prices to consumers around the world.

And yet, the World Trade Organization's Doha trade round has been languishing for over seven years as major country negotiators have been unable to reach consensus. This is in the face of an estimated 10 percent drop in merchandise trade volumes, according to WTO estimates.

There are further complications to concluding a successful Doha trade agreement brought about by the recent recession. There have been significant job losses in

> The Gulf region's advantages are based on geography, natural resources, and an already well developed production, refining and chemicals manufacturing infrastructure.

many major countries, which encourage governments to protect domestic jobs and industries. Currently, there is a serious concern and some hard evidence that protectionism will gain strength, further depressing global trade as well as making it more difficult to complete a successful new WTO agreement. Gulf petrochemical producers are long-term players, aiming to deliver affordable products to world consumers. It is certainly in our interests to work to maintain open markets and to support efforts to re-energize the Doha negotiations.

Growth in global trade is in our interests as well as those of our customers around the world.

Our region has long-term comparative advantages to be the world hub for petrochemicals production, and increasingly, the hub for more sophisticated downstream products. Neither the recession of 2008 nor any protectionist measures by parties outside the GCC region can alter this fundamental reality. The Gulf region's advantages are based on geography, natural resources, and an already well developed production, refining and chemicals manufacturing infrastructure.

In this regard, it is strategically and economically in the best interest of GCC producers to develop and expand their domestic markets. A vibrant and growing domestic market that provides stability of demand, also reduces costs for transportation and mitigates the effects of trade barriers.

To be sure, the near future will present some obstacles that will test our durability, commitment and management skills. In the Gulf we have a productive and trained workforce. We must continue to provide training to further upgrade and burnish the skills of this workforce, and we must look for ways to separate ourselves from competitors through innovation and development of proprietary technology and markets.

The Gulf chemicals industry can and must redouble its efforts for environmental stewardship, corporate social responsibility, training and employing our own nationals, promoting R&D to support new technologies and small business development, and best practices in safe operations and corporate governance. These concerns are common to many other hydrocarbon processing industries beyond chemicals such as petroleum refining and gas processing operations, thus perhaps it would be time to consider broadening this very association to include these types of companies. It is my fervent belief that every step we take to improve our understanding of these concerns and our performance in addressing them will add not only to our reputation but also to our profits. Let us all work together toward common goals in these areas. I for one hope that organizations like GPCA can serve as a catalyst.

The end products of chemicals are things in which we can take pride: life-saving pharmaceuticals; packaging to make food safer and more accessible; durable and affordable materials for clothing and shelter. A world without today's chemical products would be catastrophically poorer, less healthy, and more dangerous. May all of us in the industry renew our commitment to work together to promote sustainable growth, and to promote public awareness of the current and still-to-be-discovered benefits our industry offers for the quality of life.

Thank you.'

Overview of Tight Gas Field Development in the Middle East and North Africa Region

By Ahmed Shehata, AUC/TPS, Ahmed Aly, AUC/Schlumberger and Lee Ramsey, Schlumberger TGCOE

Abstract

As gas demand rises and operators turn to Unconventional gas reservoirs for new supplies, the need to optimize the capacity and recovery potential from this type of reservoir has risen. These Unconventional gas reservoirs represent a vast, long-term, global source of natural gas and have not been appraised in any systematic way. Unconventional gas resources – including tight sands – constitute some of the largest components of remaining natural gas resources in the Middle East and North Africa. There is an emerging focus on tight gas reservoirs in the Middle East and North Africa to feed the growing energy needs in this region and save the oil from conventional resources for export and generation of hard currencies.

The greatest challenge for tight gas is to generate economic flow, so technical capabilities are needed for effective development and production of tight gas reserves, such as mineralogy/geology, geomechanics, petrophysics, well engineering, and hydraulic fracturing.

During the last decade, 3-D seismic, horizontal drilling, and improved fracture stimulation have had significant impacts on tight gas production in many basins in the Middle East and North Africa.

In this paper we will present a documentation of all the tight gas reservoirs available in the Middle East and North Africa, the challenges of developing these difficult resources, the role of modern technologies in managing tight gas and improving recovery factors, and highlight the best strategies for field development in tight gas reservoirs to capitalize on the promising potential of these reservoirs.

The objective of this paper is to prepare data base to document all the tight gas reservoirs in the Middle East and North Africa and study the impact of technology on tight gas reservoir development in the emerging region.

Introduction

To keep step with the growth of world energy markets, international oil and gas operators have a duty to find economically and technologically viable solutions for accessing new resources. One current avenue and potential target of research is the development of unconventional gas reserves such as "tight gas".

These unconventional gas reservoirs represent a vast, long-term, global source of natural gas and have not been appraised in any systematic way. Unconventional gas resources – including tight sands – constitute some of the largest components of remaining natural gas resources in the Middle East and North Africa. Tight gas reservoir is a term commonly used to refer to a low permeability reservoir that produces mainly dry natural gas. Many of the low permeability reservoirs that have been developed in the past are sandstone, but significant quantities of gas are also produced from low-permeability carbonates, shales, and coalbed methane.

To optimize the development of tight gas reservoirs, a team of geoscientists and engineers must determine the optimum number and locations of wells to be drilled, as well as the drilling and completion procedures for each well. Often, more data and more engineering manpower are required to understand and develop unconventional gas reservoirs than are required for conventional reservoirs.

In this paper we present the challenges of developing these difficult resources, the role of modern technologies in managing tight gas and improving recovery factor, and document the available tight gas reservoirs in the Middle East and North Africa.

Challenges to the Development of Tight Gas

Fields characterized as tight gas have certain features that mean their commercial, economic, technical or operational aspects differ from other generic types of fields. They require a different level and pace of activity to 'unlock' resources, and the cost effective application of technology at scale to deliver commercial production and optimize project economics.

Here we will define the major challenges of developing this difficult resource.

1. Identifying resources

On conventional fields, reservoirs are identified by distinguishing between the porous rock that contains the hydrocarbons, and the cap rock that constitutes a permeability barrier. It is important to target the zones showing the greatest structural and sedimentary heterogeneity, where higher permeability creates the most promising pay zones. However, detecting these zones is very difficult because of the limited variation in the nature of the rock and therefore in its acoustic impedance.[1]

2. Low permeability and low porosity

Reservoir rock can be characterized using two parameters: porosity (ϕ), which expresses the volume of void space divided by the volume of the rock; and permeability (k), which indicates the ability of the formation to transmit fluids (liquid or gas) under the effect of a pressure gradient. Thus, ϕ is a good indicator of the volume of hydrocarbons potentially contained in a rock, while k provides information as to the mobility of the fluids. A rock may be characterized by good porosity, but the pores may be isolated from each other, which prevents fluid circulation (examples are pumice and partially cemented sandstone). In the case of tight gas reservoirs, the rocks have both low porosity and low permeability: even gas, with its low viscosity, cannot circulate easily. To exploit the resources from such reservoirs, more permeable zones – such as fractures or wells – must be created to allow the hydrocarbons to circulate. Both permeability and porosity are used to estimate the reserve.

3. Producing Reservoirs

Producing tight gas reservoirs is a challenging operation, yet considering the large quantities available and long-term producibility of these natural resources, such unconventional gas is regarded as a significant source of energy for the future. Tight gas could help to address the predicted deficit between energy supply and demand in the next 5–20 years. Due to the nature of tight gas reservoirs, gas migrates with great difficulty, making production highly complex. The low productivity typical of tight gas reservoirs is usually insufficient to ensure the economic viability of their development. The only solution is to connect as much of the reservoir volume as possible to the well.

4. Economic Estimation

Conventional techniques are not economically viable for tight gas reservoirs and only the development of new technologies can improve recovery factors by increasing reservoir porosity/relative permeability and thus the mobility of the gas.

Tight gas assets are defined as gas reservoirs having very low permeability compared to conventional gas resources. With low permeability and high geologic heterogeneity, production of tight gas assets requires high well densities and costly stimulation treatments, usually hydraulic fracturing.

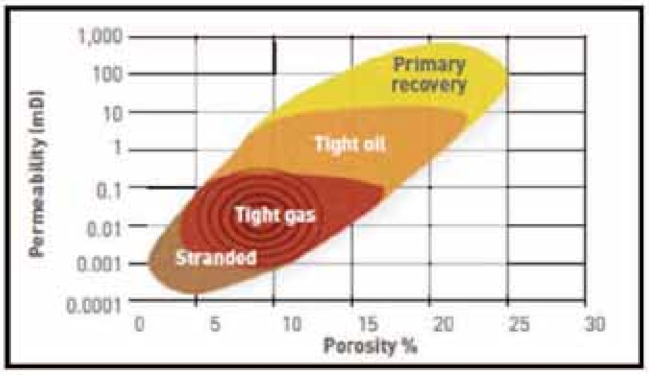


Fig. 1 The porosity and permeability of tight gas Reservoirs[1]

Largest Domestic Tight Gas Fields in Middle East and North Africa

Country	Field Name	Location of field	Geologic Age	Type of Formation	Reservoir properties		Applied Technology
					Φ,%	K, md	
Oman	Huge khazzan and makarem gas field	Central Oman, west of the giant saih Rawl gas field	Ordovician	Sandstone	7	0.1	• Wide azimuth seismic • Directional drilling • Underbalanced drilling • Hydraulic-fracture
Saudi Arabia	Gawaher	North west	Ordovician/ Silurian	Sandstone	12	>1	• 3-D seismic • Horizontal drilling • Multi hydraulic frac stages
Saudi Arabia	Mushayab		Ordovician	Sandstone	4-6	0.001-0.008	• Horizontal drilling • Fracturing Horizontal wells • Multi hydraulic frac stages
Egypt	Obaiyed	Western desert	Middle Jurassic	Sandstone	7-13	0.1-600	• Hydraulic-fracture • Directional drilling
Egypt	Abu gharadig	Western desert	Upper cretaceous	Sandstone	8.5	.01 -200	• Directional drilling • Hydraulic-fracture
Algeria	Teguentour	South west of Algeria	Silurian – lower Devonian	Sandstone	20.1	<1	• Underbalanced drilling • Horizontal drilling • Fracturing Horizontal wells • Multi hydraulic frac stages
Algeria	Krechba	South west of Algeria	Silurian – lower Devonian	Sandstone	8.5	<1	• 2D seismic • Horizontal Drilling • Geosteering • Multi hydraulic frac stages
Algeria	In Salah	South west of Algeria	Silurian – lower Devonian	Sandstone	10		• 3D multi-azimuth seismic survey • Nuclear magnetic resonance (NMR) • Directional drilling • Hydraulic-fracture • Improved proppants
Iraq	Akkas	North west of Iraq	Upper Ordovician	Sandstone	7.6	0.13	• Wide Azimuth Seismic • Underbalanced drilling • Directional drilling • Multi hydraulic frac stages
Jordan	Risha	North east of Jordan	Upper Ordovician	Sandstone with silty clay	3-7	Less than 0.124	• Directional drilling • Hydraulic-fracture
Syria	Arak		carboniferous	Sandstone interbedded with shale layer	13	>1	• 2D seismic • Directional drilling • Coiled tubing drilling • Acidizing the formation matrix

Due to these and other factors, such as environmental and resource availability, tight-gas development projects yield only marginal returns at a price of $7 per thousand btu and are very sensitive to gas price fluctuations. Financial returns, therefore, depend primarily on the volume of gas an average well delivers relative to the costs of drilling and stimulation.

Tight Gas fields involve higher levels of sophisticated drilling activity which needs high cost and the need for ongoing stimulation to progressively release the gas in place; means that the investment profile for tight gas is different from conventional reservoir, also the techniques that work in one tight basin won't work elsewhere –there's always a trial and error element to find out how to do it until you figure out how to treat the reservoir the right way. So tight gas is a play requiring cost effective technology.

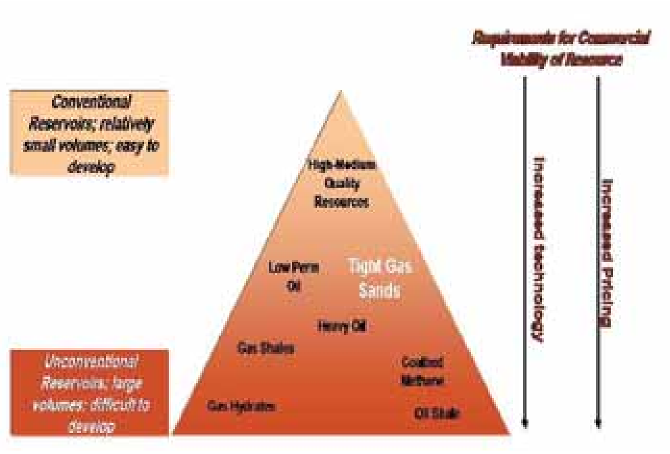


Fig. 2 Resource triangle resources vs. technology[2]

Technology for Tight Gas

A concerted technology effort to better understand tight gas resource characteristics and develop solid engineering approaches is necessary for significant production increases from this low-permeability, widely dispersed resource.

During the last decade new technologies as 3-D seismic, horizontal drilling, and improved fracture stimulation have had significant impacts on natural gas production in many tight gas reservoirs in Middle East and North Africa.

Based upon the collected information the technology used today or required to be developed to recover tight gas reservoirs was assessed for the following key areas:

1. Seismic Technology
2. Formation Evaluation Technology
3. Drilling Technology
4. Completion & Stimulation Technology
5. Other Technology Focus

1. Seismic Technology

The new seismic technologies increase the ability to accurately detect "sweet spot" areas of unconventional gas plays which are typically found by pattern drilling. By finding these sweet spots ahead of drilling, the number of poor performing, subeconomic wells would be reduced, thus improving the overall economics of the program and creating an incentive for more participation. It would also reduce the overall number of wells/drill-sites in a given geologic region, yet maintain the same overall recovery. This would create a more environmentally attractive development plan.

Seismic Methods to identify "Sweet Spots" in tight gas:

1. Time-lapse multicomponent seismic monitoring of pressure depletion in tight-gas development can be used to increase recovery efficiency.[3]
2. 3D multi-azimuth seismic survey is introduced by Total.
3. Wide azimuth seismic and leading processing techniques: it allows "See" reservoirs more clearly, choose best drilling locations , and detect fractures. BP applied it in Algeria's In Salah fields and Oman's Khazzan and Makarem fields
4. Micro-seismic fracture mapping and post fracture diagnostics: improved understanding of hydraulic fracturing in horizontal wells so that designs can be improved.
5. Cableless seismic surveying techniques: Improved density of receivers, speed up acquisition, more sophisticated data transfer, and eliminate much of the ground disturbance associated with conventional seismic. It is useful in more remote locations where lying of cable presents its own challenges and it is introduced by BP

2. Formation Evaluation Technology

To properly complete, fracture treat, and produce a tight gas reservoir, each layer of the pay zone and the formations above and below the pay zone must be thoroughly evaluated.

The most important properties that must be known are pay zone thickness, porosity, water saturation, permeability, pressure, in-situ stress, and Young's modulus. The raw data that are used to estimate values for these important parameters come from logs, cores, well tests, drilling records, and production from offset wells.

The objectives of Formation Evaluation are to ascertain if commercially producible hydrocarbons are present, determine the best means for their recovery, to derive lithology and other information on formation characteristics for use in further exploration and development. Because tight gas reservoirs are normally also low porosity reservoirs, the importance of detailed log analyses becomes critical to understanding the reservoir. For example, if an error of 2 porosity units (p.u.) occurs when the porosity is 30%, it is normally not critical. The difference between 28 or 30% porosity will not lead to much error in net gas pay, water saturation, or gas in place. However, the same 2 p.u. error applied to a reservoir in which the porosity is 8% is a much more significant problem. The difference between 6 and 8% porosity can cause significant errors in estimates

Fig. 3 Formation evaluation process

of net gas pay, water saturation, and gas in place. As such, careful preprocessing of log data and detailed petrophysical analyses of all openhole logging data are very important in the analyses of tight gas reservoirs.
The formation evaluation begins at exploration and extends to development and production optimization.

Logging Technology
• A new nuclear magnetic resonance logging technique was developed. The tool has operating and measurement advantages in tight gas sand formations over existing nuclear magnetic logging tools. The advantages are: elimination of the need to condition borehole fluids prior to logging a hole; higher sensitivity per unit sample volume; shorter instrumental dead time; and potential for greater formation penetration. The new technique has been laboratory tested in tool geometry.

• Tight reservoirs are often associated with washed-out and rugose borehole. Apparent porosity from pad type logging tools such as density, shallow resistivity and NMR is usually too high (and often useless or misleading). Even sonic tools read too high because of signal attenuation and associated waveform "stretch".[4]

• Bi-modal Acoustic Sensor provides wireline-quality compressional and shear slowness (Δt) logs in both fast and slow formations. The dual-frequency transmitters and dual seven-receiver array configuration ensure a superior signal-to-noise ratio and measurement redundancy for service reliability.

• Compensated Thermal Neutron Sensor provides accurate porosity, fluid type and lithology information for real-time decision making and wireline replacement applications.

• LWD formation tester. It is possible to obtain real-time direct pore pressure measurements, with accuracy and precision comparable to that of wireline formation testers. By using it we can obtain real-time fluid gradients and fluid mobility (permeability/viscosity indicator), and identify fluid contact points, and de-connectivity/compartmentalization, and depletion.

• Fractured and tight reservoirs require very careful petrophysical analysis in order to avoid serious overestimation of reserves.

Formation Testing
The low permeability of these reservoirs slows down their response to pressure transient testing so it is difficult to obtain dynamic reservoir properties and, therefore, to characterize gas reserves.

Obtaining reliable and accurate formation pressures in microdarcy rock is a formidable challenge, but it can help determine drainage areas and appropriate well spacing for tight gas reservoirs. It is possible to measure formation pressure accurately in micro darcy rock. Dedicated tools were designed and used because conventional methods were unable to measure pressure accurately enough for well-spacing decisions. A 4D-pressure pilot was designed and installed to measure pressure drop at two observation wells equipped with pressure gauges.

3. Drilling Technology
The drilling of tight gas wells borrows from the extensive suite of technologies already made available through the conventional oil and gas industry. However, there are several difficulties that have been experienced with direct application to tight gas plays.

Middle East and North Africa drillers have directed their time and talents in capturing and implementing "drilling best practices." These "best practices" have made dramatic improvements in: (1) drilling safer, (2) drilling with less damage to the reservoir and less impact on the surface environment, (3) improving rig mobilization, and (4) drilling with less rotary drill time.

Drilling applications of tight gas reservoirs:

1. Drillbits
• A new generation of PDC cutters that have improved the rates of penetration as much as 118% above previously used bit technology.

2. Real-time sweet-spot detection while drilling
• It allows the steering of the drill bit to most productive areas of the reservoir.

3. Directional Drilling
• Allows the alteration of the drill bit's dip and orientation in order to maximize the production response by

optimizing the ability to cross-cut pay zones and by intersecting more fracture. Enables the possible use of new drilling patterns.

4. Multi-Lateral Drilling
• Allows more than one borehole to be drilled from a single well by drilling multi-lateral wells underground from the original surface wellbore.
• Enables the possible use of new drilling patterns.
• Seek to optimize the non-pay zone well section cost by drilling off the main bore

5. Underbalanced Drilling
• Mud pressure is kept lower than the formation pressure, thereby preventing invasive formation damage and the associated risk of clogging. e.g. Implemented on the Hassi Yakour tight gas field in Algeria during the second half of 2006.

6. Horizontal drilling
• Provides a large drainage area per well; horizontal wells in Saudi Arabia become attractive because of the relatively rapid payout from initial production rates.
• Reducing the number of wells required to drain the reservoir.
• Allow operator to take advantage of highly heterogeneous or layered reservoirs.
• It provides high productivity

7. Slim hole technology
• It drives the potential for cost reductions because a slimmer hole requires smaller drill bits, narrower production tubing and less cement, which results in fewer materials being used.

8. Coiled Tubing Drilling
• It increases rate of penetration and improves durability.
• Fast trip times in and out of the wellbore, because there is no need to disconnect or reattach drill pipe when tripping.
• Coiled Tubing drilling rigs are small and light
• Leave a smaller footprint
• It allows rapid rig moves.

4. Completion & Stimulation Technology

Completing wells consists of testing, setting and cementing of production casing, well stimulation, and installation of tubing and downhole production equipment. Unconventional wells are tested by measuring the formation pressure to determine what type of stimulation is needed.

Due to the complex dynamics at play in these reservoirs, stimulation is an important part of unconventional gas production.

Stimulation applications for tight gas reservoirs:
• Hydraulic-fracture stimulation improves the productivity of a well in a tight-gas reservoir because a long conductive fracture transforms the flow path natural gas must take to enter the wellbore.
• Multi-stage fracture treatments that can increase the production
• Fracturing Horizontal wells is even more attractive than multilateral completions, especially in tight, thick formations. It increase production rate by 2–3 times rate of vertical well.
• Develop new fracturing fluid which is strong, light-weight and does not damage the reservoir as water- based (gels and slick water) and gas-based solutions (such as nitrogen and CO_2).
• Use spherical proppant that produce better porosity and permeability in the proppant pack than irregularly shaped and sized sand particles and its idea is once proppant is placed in a fracture, the idea is to have it stay there to keep a pathway open for the gas to flow toward the wellbore.
• Low pressure stimulation technique used to reduce formation pressure (by dewatering the free gas zone).
Microseismic monitoring was used to measure the azimuth, length and height of a hydraulic fracturing and providing a survey design and fracture characterization.

Completion applications for tight gas reservoirs:
• Equipment and electronic sensors that can withstand the high temperature and pressure regimes.
• Expandable pipe for larger bottom-hole production equipment without adding number of casing strings.
• "Smart well" technologies to enable the multizone completion and controls while preventing costly future well intervention.
• Principles of Propellant/Perforating: The option that promised best results was to use the new propellant-perforating stimulation techniques. Propellant is a combination of an oxidizer and a fuel burns rapidly when ignited, generating large volumes of high-pressure combustion gases. The burning of the propellant produces a pressure load on the formation that is below the compressive yield strength of the formation rock. As the pressure increases, strain energy is accumulated in the rock matrix until the circumferential stress around the wellbore exceeds the strength of the rock and a fracture is initiated.
• Casing Conveyed Perforating System (CCPS), which has revolutionized multizone fracturing operations. The CCPS facilitates pinpoint stimulation of multiple

pay intervals in a relatively short time and improves stimulation quality, hydrocarbon recovery and well economics.

• New systems not only for propellant assisted perforating improve penetration into the tight formation, but it also cleans up after itself, in effect stimulating the near-wellbore area. This reduces the horsepower required for subsequent fracturing operations.

5. Other Technology focus

• Petrophysics is a critical technology required for understanding low-permeability reservoirs.
• Geomechanics and subsurface understanding is a critical component in understanding the nature of the formation. All companies recognise the need to use geomechanics to assess natural fracture patterns.
• Permeability – magnitude and direction
• Distribution of natural fractures
• Change of permeability with depletion

Conclusion

We conclude that approaching tight gas will require paradigm shift of what we are doing today at the Middle East and North Africa. It requires an integral approach of all the technology available as highlighted in this paper to unlock this big resource for the future of the region and saving oil for exporting, petrochemical industry, and generation of hard currency.

References

1. Total, 2006 “Tight Gas Reservoirs”, 2006

2. Stephen A. Holditch, SPE, Texas A&M U , “Tight Gas Sands”, paper 103356-MS, June 2006

3. Thomas L. Davis and Robert D. Benson, “Tight-gas seismic monitoring, Rulison Field, Colorado”, April 2009.

4. M.M. Abu-Shanab, BAPETCO, E&P, EGPC/Shell J.V., Egypt, G.M. Hamada, A.A. Abdel Wally, Faculty of Engineering, Cairo University, Egypt, M.El. Oraby, Halliburton energy Service, Egypt, “ IMPROVED POROSITY ESTIMATION IN TIGHT GAS RESERVOIRS FROM NMR AND DENSITY LOGS”, paper SCA2005-57 presented at the International Symposium of the Society of Core Analysts, Toronto, Canada, 21-25 August 2005

5. The National Petroleum Council (NPC), 2007 “UNCONVENTIONAL GAS”, 18 July, 2007

6. James R. Ammer, Gary L. Covatch, Gary P. Sames, Thomas H. Mroz, William J. Gwilliam, U.S. Department of Energy, National Energy Technology Laboratory “Technology for Increased Production from Low-Permeability Gas Reservoirs: An Overview of U.S. DOE’s Gas Program - Successes and Future Plans” paper 60310-MS SPE Rocky Mountain Regional/Low-Permeability Reservoirs Symposium and Exhibition, 12-15 March 2000, Denver, Colorado

7. PTAC, 2006 “Unconventional Gas Technology Roadmap”, June, 2006

8. G.C.Naik, “Tight Gas Reservoirs – An Unconventional Natural Energy Source for the Future”

9. Dutton S., Clift S., Hamilton D., et. al., 1993, Major Low Permeability Sandstone Gas Reservoirs in the Continental United States, Bureau of Economic Geology, University of Texas, Austin.

10. Gray, J. 2005. “New stimulation techniques for unconventional gas”, 7th Annual Unconventional Gas Conference, Canadian Society for Unconventional Gas, November 8-10, 2005.

Technology and Team-Based Approach Yields Saudi Arabia's Longest Fully Cemented Horizontal Liner

By Marlio Campos Ramos/Saudi Aramco, Sameh Hussein and Kirby Wedewer/Baker Hughes Inc, Ansgar Dieker BJ Services Arabia Ltd.

Abstract
Saudi Aramco's "M" Field is located offshore and will be developed using over 300 wells with a combination of land and offshore drilling facilities.

Well number M-A is a land-based, power water injector well, drilled to an offshore bottomhole location. The resulting well design dictated directionally drilling an extended-reach well with an 8½-in. horizontal-hole section over 13,900 ft (4237 m) in length.

It was apparent from the outset that directionally drilling the 8½-in. section was going to be extremely challenging. Once drilled, running and cementing the 7-in. liner would present a host of additional difficulties. To ensure a successful outcome, Saudi Aramco assembled a dedicated team of Operator and Service personnel to review all aspects of this openhole section and resulting liner running operations.

The latest in directional drilling technology was used to ensure the exacting directional control needed to deliver the wellbore. In addition, running the over 14,400-ft-(4389-m)-long liner required the use of new and innovative liner hanger technology to overcome any challenges encountered during liner deployment.

This paper will outline the planning, methods, and equipment applied to deliver the resulting 8½-in. hole section, and successfully deploy Saudi Arabia's longest-ever cemented 7-in. liner.

Introduction

Field Description
"M" field is an offshore field located in shallow water depths of 3-16 ft (1 to 5 m). The field has been produced since its discovery, and the current plan is to increase production dramatically by drilling more than 300 onshore and offshore wells.

However, the location of the field in shallow water makes developing the wells even more challenging. Saudi Aramco's offshore drilling fleet consists of jack-up rigs that cannot operate in shallow water. The preliminary planning showed that 37 platforms are needed to be installed to meet the production target, and major dragging works have to be done for channels to facilitate the movement of marine vessels and rigs.

After an economic feasibility study to save approximately US$1.10 billion, the decision was made to build 11 offshore platforms (4 production and 7 injection), 15

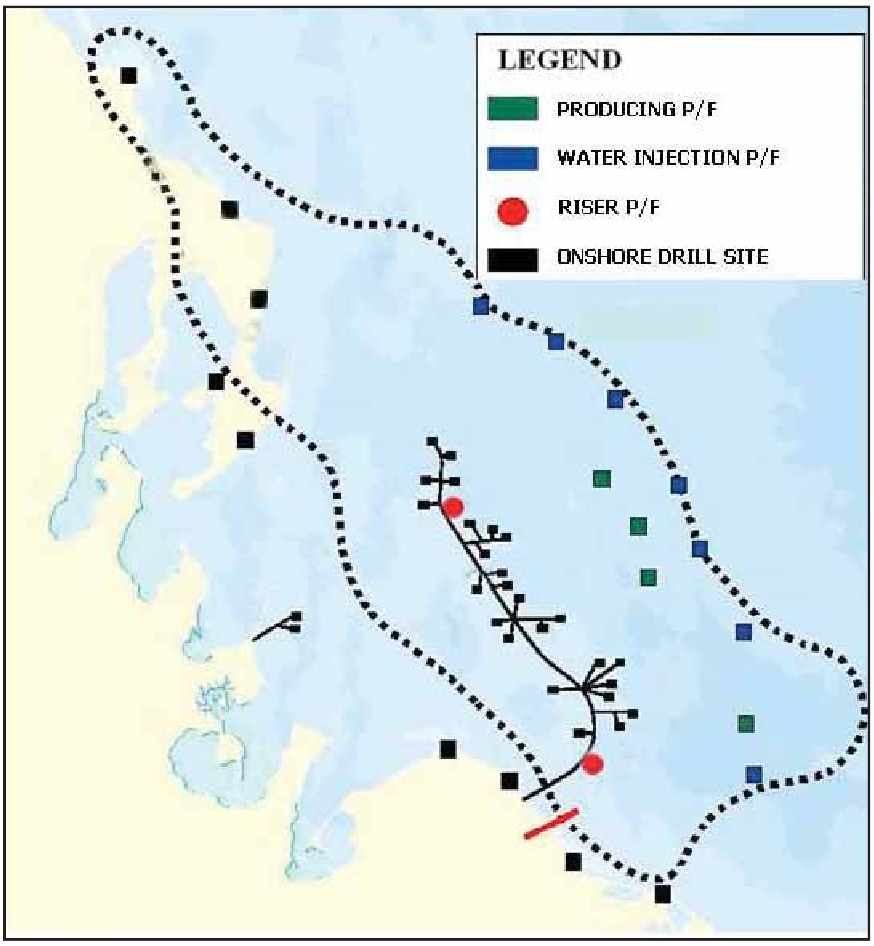


Fig. 1

onshore drill sites and an offshore causeway that consisted of 27 drilling islands connected by over 41 kilometers of road (Fig. 1).

Well Design and Challenges

Drilling engineering and directional drilling

The power water injector wells involve drilling below the oil-water contact into flushed and water-wet formation. The 28,000-ft (8534-m) measured depth on these ERD wells make them some of the most challenging in the world (Fig. 2). Targeted carbonate formation layers are typically denser than the production horizon and have intervals separated by dense anhydrite. Production technologists will seek to cross 3 to 4 layers so as to be sure of full sweep efficiency when water injection begins. The layers are fairly flat, and the planned wellbore on well M-A intersected at a high angle (87°) to provide adequate vertical section.

Liner operation

With the above drilling challenges, and ensuring that the liner reaches TD, come the liner challenges:

1. The length of the liner will be 14,428 ft and with having the 9-5/8-in. casing depth at 10,006 ft (3050 m) will require 4,428 ft (1350 m) of casing to be run in the open hole before picking up the liner hanger assembly, which will include the risk of potential sticking during picking and make up the liner hanger assembly.

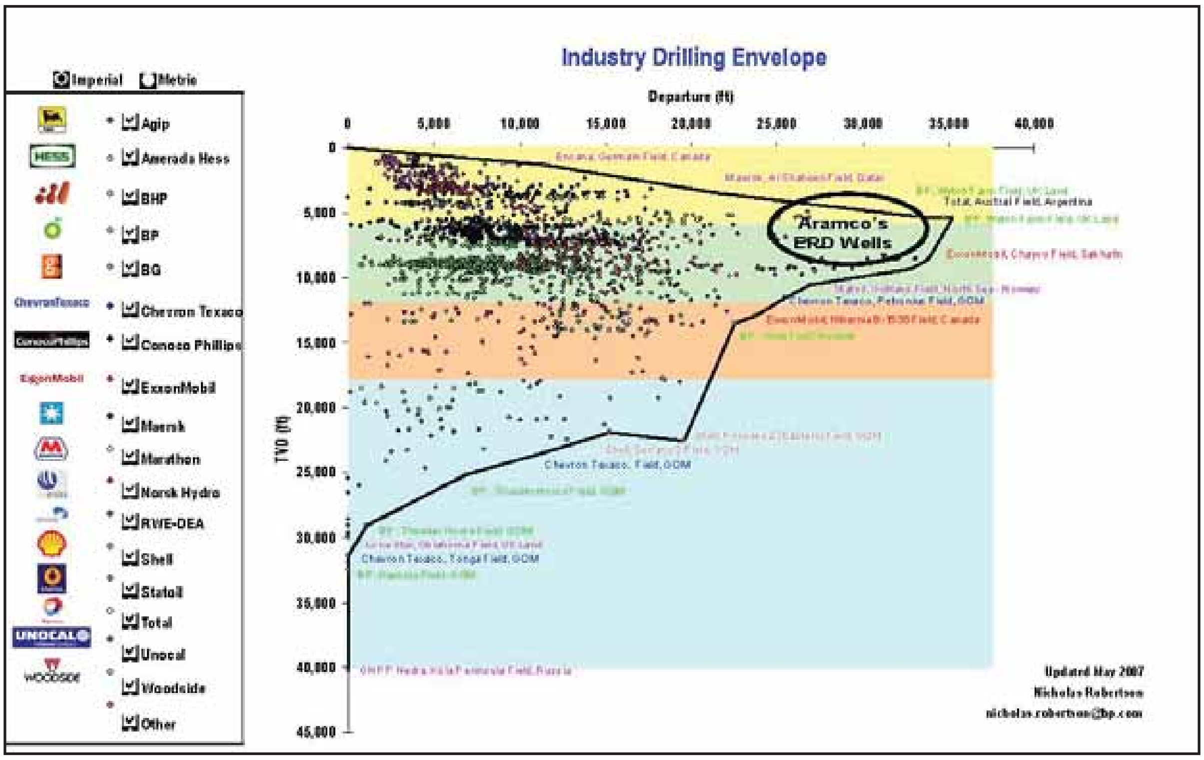


Fig. 2

2. With the torque and drag simulation of the well, it was concluded that with 2,000 ft (610 m) in the 8½-in. open hole, we will not be able to rotate the liner to bottom due to the torque limit on the casing string thread; thus, you have to push and circulate the liner to bottom with high circulating rates.

3. Ensuring a reliable liner operation and equipment, this includes setting the liner hanger and hanging the weight of the liner on it as well as setting the liner top packer to seal the top of the liner.

These challenges must be addressed with a different approach rather than conventional deviated or horizontal wells. Ideas like floating the liner to bottom, upgrading the liner threads, using a special type of liner hanger to enable circulation with high rates and pressures, and using liner wiper plug systems which will isolate the cement during displacement inside the drillpipe and the casing to prevent contamination.

Cementing

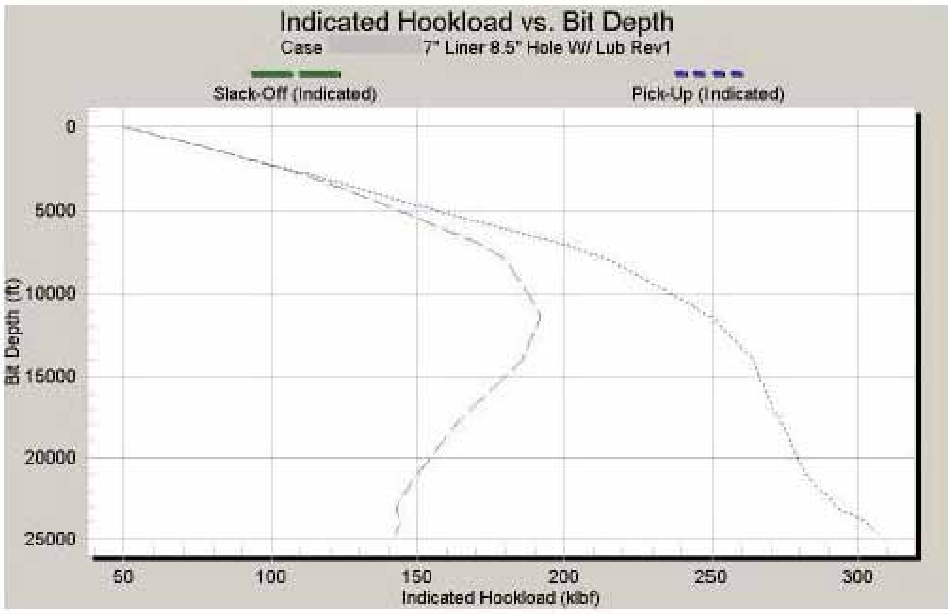
Part of the successful completion of the water power injector was the cementation of the 7-in. liner. This liner had a total openhole length of 13,921 ft (4243 m) with an overlap into the 9⁵/₈-in. casing of 503 ft (153.3 m) and a requirement for 500 ft (152.4 m) cement above the top of liner. The maximum angle of the deviated section was 87. Considering the length and the high deviation of this hole section, it was mandatory to apply the best and latest cementing practices used in the industry. The parameters and practices reviewed for the successful cementing of the liner are presented in this section:

Laboratory design

- Selection of temperatures – typical API temperature calculations cannot be applied; therefore other methods were reviewed and implemented.
- Slurry properties – to achieve good zonal isolation in horizontal wells, it was paramount to have a stable slurry tested at the correct downhole parameters.
- Thickening time selection criteria – due to the complexity of the operation and the long job time, it was crucial that the tested thickening time reflect as close as possible the projected total job time, allowing for time due to possible job variations.

Mud removal

- Centralizers – the correct selection of the type of centralizer was important for the mud removal and the deployment of the liner.
- Spacers – well cleanup and wetting of the formation/casing in an ERD well are becoming more difficult and therefore the standard procedures needed to be reviewed.



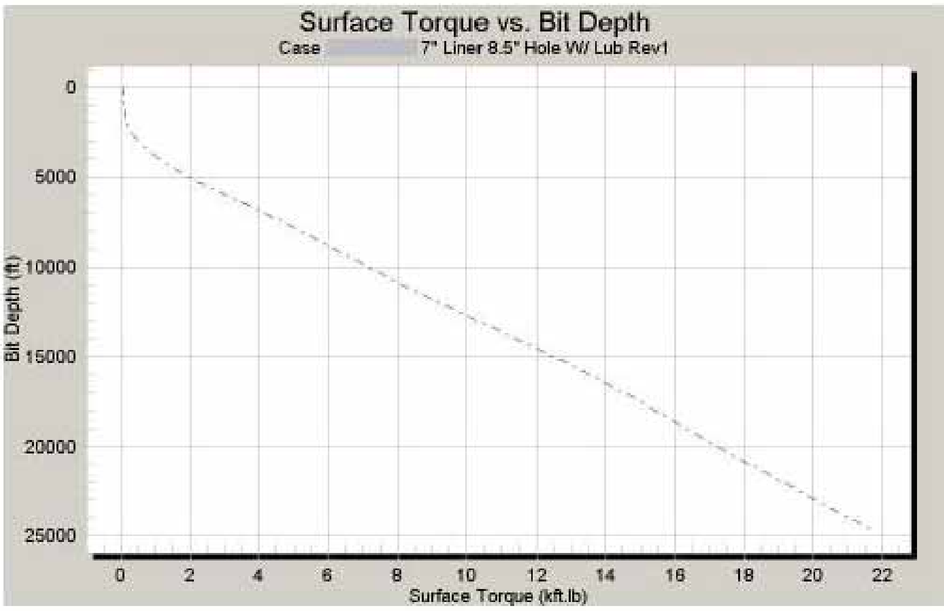


Fig. 3

Operations

• Equipment – any failure of the equipment can result in extensive remedial work being required, therefore the reliability needed to be guaranteed.

Planning

A planning team was selected with focal point members from Saudi Aramco drilling engineering, directional drilling, liner operation, and cementing – the four core members for this operation. The plan summary for each was as follows:

Drilling engineering and directional drilling

ERD wells have certain requirements of the drilling rig. A 3,000-hp "skeleton" rig was required with an increased pump rating but without big derrick and drawworks. To ensure adequate hydraulics, the stand-pipe pressure rating requirement was greater than 5,000 psi (345 bar) and three mud pumps were required for continuous service. Adequate drillpipe setback area was required for 28,000 ft drillpipe on M-A well. Without the setback area, trips in and out would need to be done sideways. Drillpipe reccomendations were as follows: 5½-in. drill-

Fig. 4

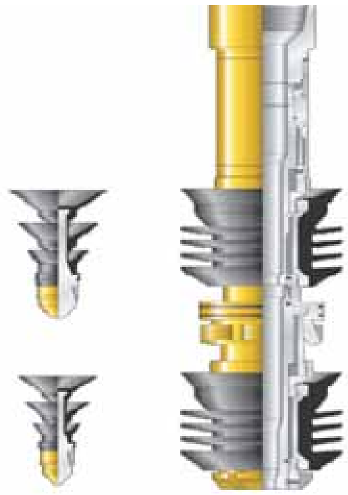


Fig. 5

pipe XT57 for strength and hydraulics. Hard banding was required on all drillpipe. Required top-drive rating: torque output greater than 45,000 ft/lbs and able to provide continuous RPM of 150. Automated pipe handling was requested to reduce exposure and mitigate safety concerns.

Bits were designed specifically for the field application with at least 50 thousandths of an inch undergauge. The special gauge was used so that less force was required from the RSS to achieve the required dogleg severity. The bits were designed to be dynamically stable with reduced vibration and depth of cut control. Aggressiveness was matched to maximize penetration rates.

Liner operation

We could not change the thread of the casing to a high torque thread; therefore, we could not rotate the liner to bottom and, since liner floating techniques had not been tried before and with the risk associated with it, an extensive torque and drag simulation was run considering all the directional drilling scenarios and friction factors for both the casing and the open hole, which showed that, with the current drag, we have enough liner weight to get the liner to bottom (Fig. 3) and to enable the liner to be washed to bottom with high circulating rates. This will generate high circulating pressure. The risk of pre setting the liner hanger off bottom was eliminated by using the control set liner FlexLock liner hanger (Fig. 4), which includes a new technology of dual setting piston that will prevent the liner hanger from being preset, as the two liner piston did see the same pressure and thus the liner hanger will not set until you isolate the lower piston by dropping the setting ball.

Also to be able to push the liner to bottom a special liner setting tool (HR) was used in which you can push, pull, and rotate the liner during running; also a special cementing plug was used that incorporates a lead and follow plug system (LFC) was used to isolate the cement during displacement inside the drillpipe and casing (Fig. 5).

Cementing

Laboratory design

The need for timely confirmation testing in remote locations can be addressed by having a mobile laboratory at the location. For well M-A, the operator's standard procedures dictated that final confirmation testing be conducted both at the Operator's and the Service Company's laboratory. This raised a logistical issue, with the field-mixed water, cement, mud, and freshwater samples having to be sent from the remote location into town, some distance away. Plans therefore had to be placed to ensure the timely preparation and delivery of the samples.

Selection of temperatures:

One of the main factors for placing the cement correctly is the selection of accurate testing temperature. Due to the long horizontal section (> 6,000 ft, 1829 m), it is common practice for the Operator to use the BHST as the BHC Test Temperature. Various temperature calculation software programs also supported the same. The challenge on well M-A was the limited availability of offset data for temperature to assist in the initial design phase. The decision was made to use the measurement while drilling (MWD) temperature as the base and correct the data on the final temperature log after the well was drilled. During the drilling phase of this hole section, temperatures of up to 300°F had been recorded and the slurry was initially tested for this parameter. After the final log, a temperature of 246°F was measured and used for the confirmation tests.

Slurry properties:
The rheological properties are a very important indicator of the stability of the slurry as well as determining the appropriate fluid regime to optimize mud removal[1, 2], calculate the pressures and the relevant equivalent circulation densities (ECDs). To avoid the generation of channels on the high side of the pipe and the uniform placement of a slurry across the entire openhole section, the slurry needed to possess low fluid loss control with zero free water and segregation development. For this job, latex slurry with a density of 122 pcf was chosen. The slurry was found to be very stable even under small variations in density changes. This was very important where formation permeability or even gas migration could be an issue.

Thickening Time:
For conventional liners, it was typical to accept a thickening time of about 3 hours over the designated job time. For well M-A, the extensive operation time as a result of the large slurry and displacement volumes, warranted the re-assessment of the risk and adjustment in thickening time criteria. For a predicted job time of 7 hours, the thickening time required was placed at 12 to 13 hours. It was calculated for the reason that in case of losses the pumping and displacement rate for the slurry and mud could have been reduced to as low as 2bpm, without getting too close to the tested pumping time.

Mud removal
Centralization:
Pipe rotation or pipe reciprocation are methods commonly used during liner cementing to achieve good mud removal[1, 2]. The lifting capacity of the rig and the strength of the pipe connections made it impossible to use any of these techniques. Therefore it was important to obtain the minimal API standoff of 67% in this highly deviated section. It was crucial to select the correct type of centralizers to achieve sufficient standoff and improve mud removal, whilst still minimizing the running forces, ensuring that the liner can be deployed to the desired depth. Both bow type and solid body spiral centralizers were modeled to obtain the desired 67% standoff. The solid body zinc alloy centralizers were selected with the hydraulic job simulator program, showing an adequate standoff of 72.6% will be achieved within an average caliper hole size of 8.835 in.

Spacers:
Proper spacer selection depends on the mud type, its properties, wellbore geometry, flow regime, density of the mud and cement, as well as compatibility tests among the mud, cement, and spacer[1, 2]. Taking all these factors in consideration and utilizing the service company hydraulic simulation program, the use of a spacer train produced the most compelling advantages. With the oil-based mud, the combination of flushes and weighted spacers will contribute to efficient mud removal and lead to the desired cementing result.

The spacer train was led by 50 bbls of base oil at low viscosity. The Newtonian fluid is in turbulent flow at very low pump rates. This fact will result in pushing ahead the mobile mud and contributing to the compatibility of the drilling fluid. The base oil was followed by 50 bbls of water flush containing surfactant to water-wet the formation and casing, which contributes to the bonding of the cement. Then 75 bbls of 100-pcf-weighted spacer with barite and surfactant was pumped to ensure the equivalent mud weight of 78 pcf was kept throughout the entire cementing operation. Finally this was followed again by 50 bbls of water flush and 75 bbls of weighted spacer, with the same properties as previous.

Operations
Equipment:
The length of the liner, hole geometry and desired overlap volumes, resulted in the planned slurry volume of 457 bbls. The density would be 122 pcf latex slurry. The typical policy of the operator is batch mix liner slurries. In this case, the logistic would have required the use of up to five batch mixers plus backup. This was evaluated to be too risky with the likelihood of having a mechanical failure. It was therefore decided to use the latest 3rd generation cementing mixers provided by the service company with proven slurry density control and redundant systems to mix and pump the whole slurry volume on the "fly."

Execution

Drilling engineering and directional drilling
Dogleg severity was minimized using AutoTrak X-treme with CoPilot. Real-T-time downhole pressure measurement was done with both flow-on and flow-off. ECD was monitored with CoPilot; cutting beds were mitigated by maintaining the appropriate pressure window. Stiffer bottomhole assemblies (BHAs) were designed to

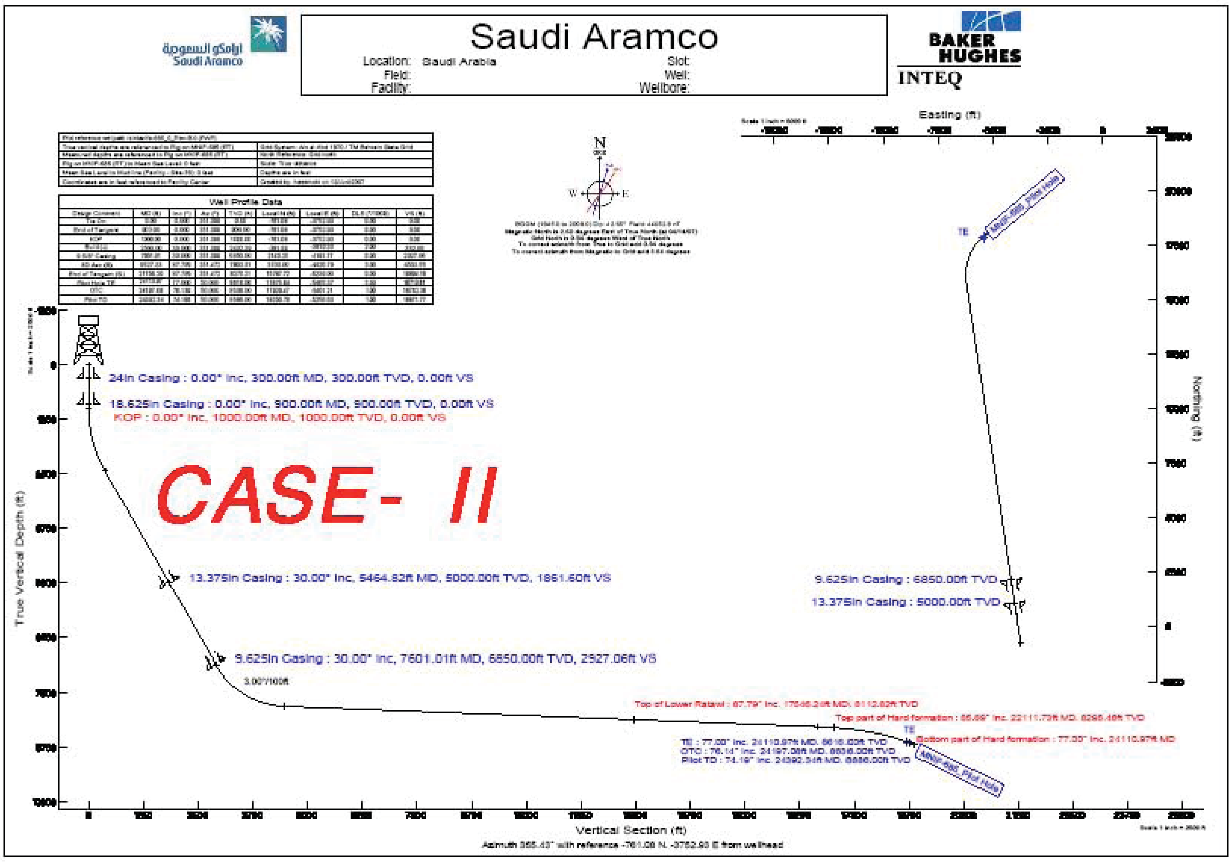


Fig. 6

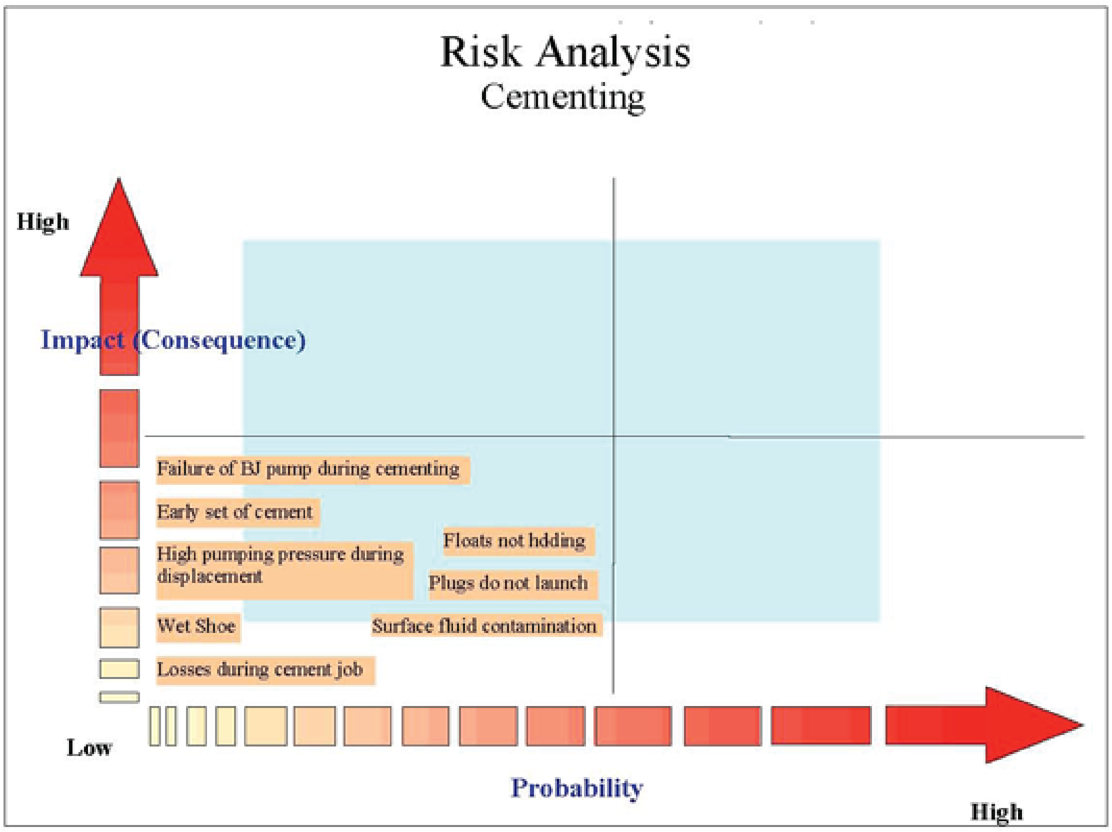
minimize flex components. The use of CoPilot increased the success of negative drill break procedures and detection of possible cyclic borehole effects. Early detection and intervention allowed the team to properly address unplanned, high local doglegs.

Considerations for the long, 14,000-ft (4267-m), 8½-in. hole-section on the M-A well were torque & drag, proper hole cleaning, and adequate weight transfer. Slow rate of penetration (ROP) and tough drilling conditions were anticipated in the upper part of Buwaib and Lower Ratawi base; therefore, bit life was a concern. Well trajectory solutions were considered and ultimately the trajectory was adjusted to minimise drilling through these problematic formations. Steering and directional control were maintained through the long open hole at 87 and dogleg severity was kept less than 2.0 deg/100ft, creating an exceptionally smooth wellbore (Fig. 6). Extensive wiper-tripping procedures were used with periodic sweeps used to ensure adequate hole-cleaning and lubricants were used resulting in 15%–20% torque reduction. Fully integrated mud-logging services were also provided to monitor hole-cleaning.

The performance on M-A well was greatly improved by the introduction of a new downhole drilling sensor tool called CoPilot. The CoPilot is an integrated downhole dynamics MWD tool that offers a high speed data acquisition and processing system based on an array of dynamics and mechanical sensors. Integrated into a high-speed rotary closed-loop drilling system, powered by an integral modular motor, a step change in drilling performance was achieved. In this application, the dynamics tool was placed between the modular motor and the steering head to give the directional drilling crew a clear understanding of the true environment being encountered by the steering head and bit (Fig. 8). Optimization of performance resulted in increased overall ROP. A feature of these tools that most interests the reservoir department is the capability for geosteering to very precise tolerances. RSS tools can steer to a true vertical depth target or, if preferred, hold an exact angle to intersect zones of interest, as in the case of ERD wells.

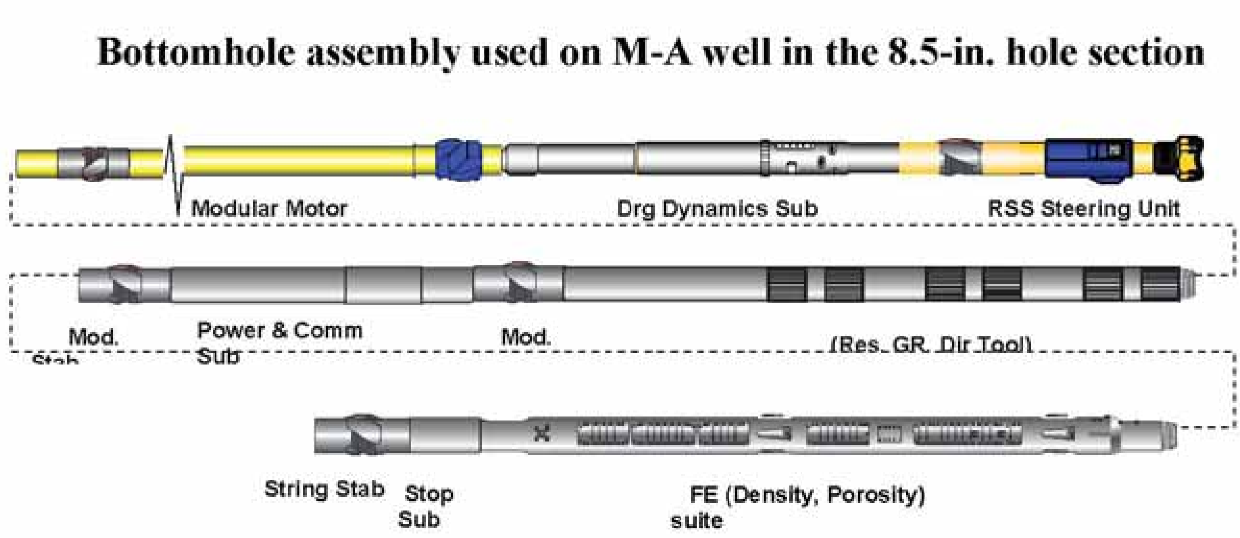
Liner operation

The liner consisted of a three-joint shoe track with a double valve reamer shoe, two joints of 7-in. 26# N. Vam casing, two single valve float collars, one joint of casing and a Type 1 LFC landing collar. The liner consisted of an additional 355 joints of casing. A hydraulic ControlSET FlexLock III liner hanger, RS nipple and ZXP packer made up the liner hanger assembly. The



Risk Analysis
Cementing
High
Impact (Consequence)
Failure of BJ pump during cementing
Early set of cement
High pumping pressure during displacement
Floats not hdding
Plugs do not launch
Wet Shoe
Surface fluid contamination
Losses during cement job
Low
Probability
High

Fig. 7



Bottomhole assembly used on M-A well in the 8.5-in. hole section
Modular Motor
Drg Dynamics Sub
RSS Steering Unit
Mod. Stab
Power & Comm Sub
Mod.
(Res, GR, Dir Tool)
String Stab
Stop Sub
FE (Density, Porosity) suite

Fig. 8

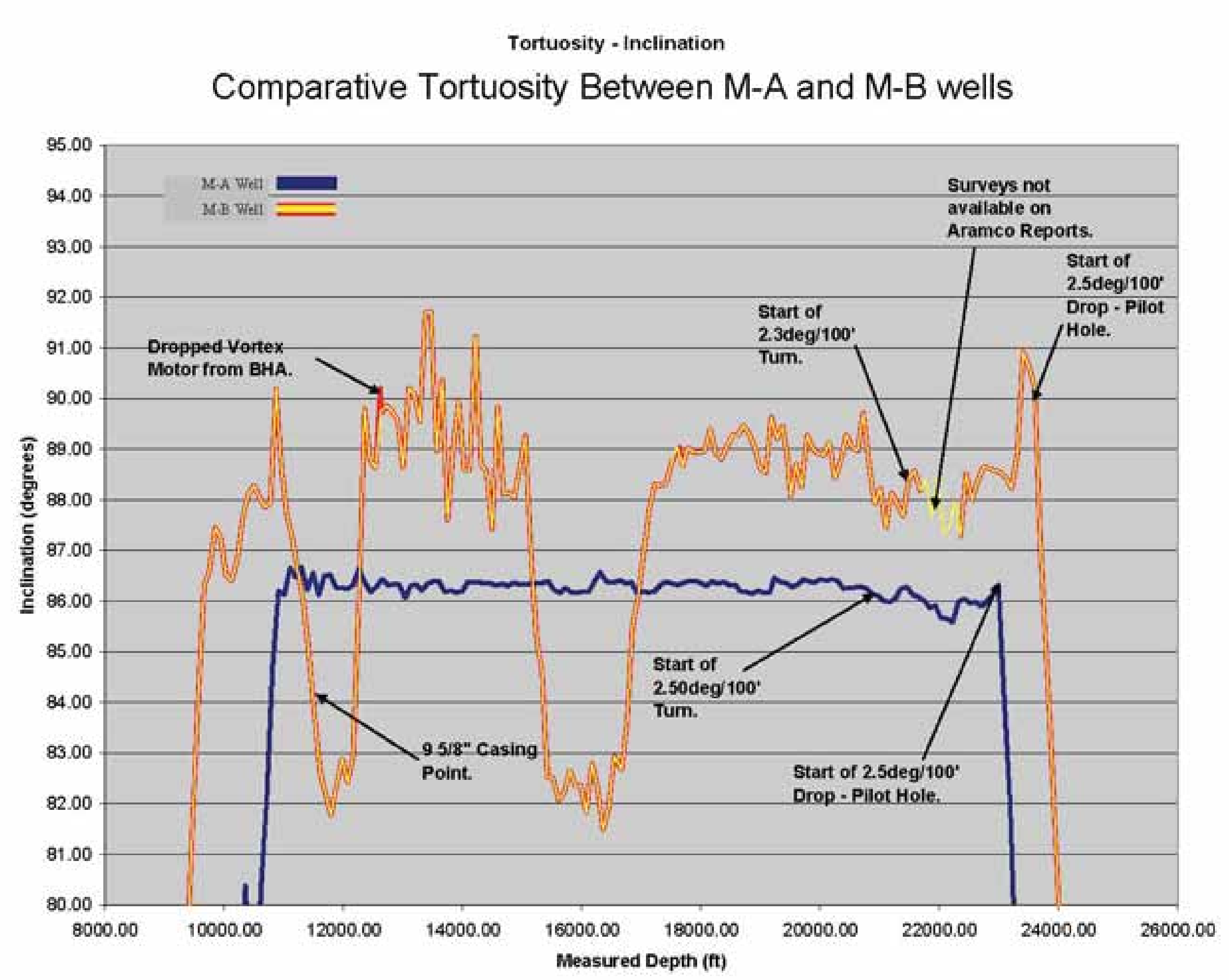


Fig.9

total length of the liner was 14,437 ft (4400 m). The theoretical air weight of the liner was calculated at 365 klbs, with an actual pickup weight of 265 klb and 170 klb slacking off. The liner was successfully deployed to the desired depth, with bottom of liner at 23,927 ft (7293 m).

With the liner at TD a trial test of the ControlSET liner hanger technology was successfully completed by circulating with high flow rate of 12 bpm at 3,465 psi (238.9 bar). The ControlSET liner hanger was then set and the running tool released. The well was conditioned and the cement job was undertaken. An LFC liner wiper plug system was used on the well. While cementing the liner, there was no indication of the liner wiper plug bumping. However, it should be noted that the decision was taken to only over displace ½ of the casing volume below the LFC landing collar (½ shoe track volume). In general the cement job went without incident, and no obvious anomalies were observed.

The liner top packer was successfully set, and tested. The liner running tool was pulled out of the top of the liner with no problem. Drillpipe was pulled until the bottom of the string at 8,500 ft (2591 m) and circulated "bottoms up" and 220 bbl of pre-flush and spacer was recovered. An additional 50 bbl of pre-flush and spacer was recovered at the top of liner when an 8½-in.-OD cleanout assembly was deployed.

Cementing

After careful consideration of all the cementing parameters and elements, a risk assessment of the cementing operation was performed and communicated to all involved personnel. This tool was used to increase awareness and focus on the cementing operation. (Fig. 7)

The mobilization for the cement job took place on 15 January 2008. Upon arrival at the location, the crew had a briefing with the operator's safety officer and the company man. At this point the cementing supervisor, in control of the cementing operation, held a pre-job meeting, outlining the equipment as well as the final execution plan for the operation. The mixed water was prepared in the cementing tanks and sent to both the operator and service company laboratories for confir-

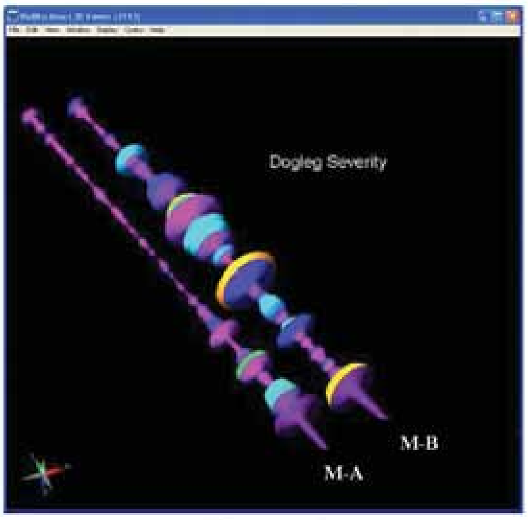


Fig.10

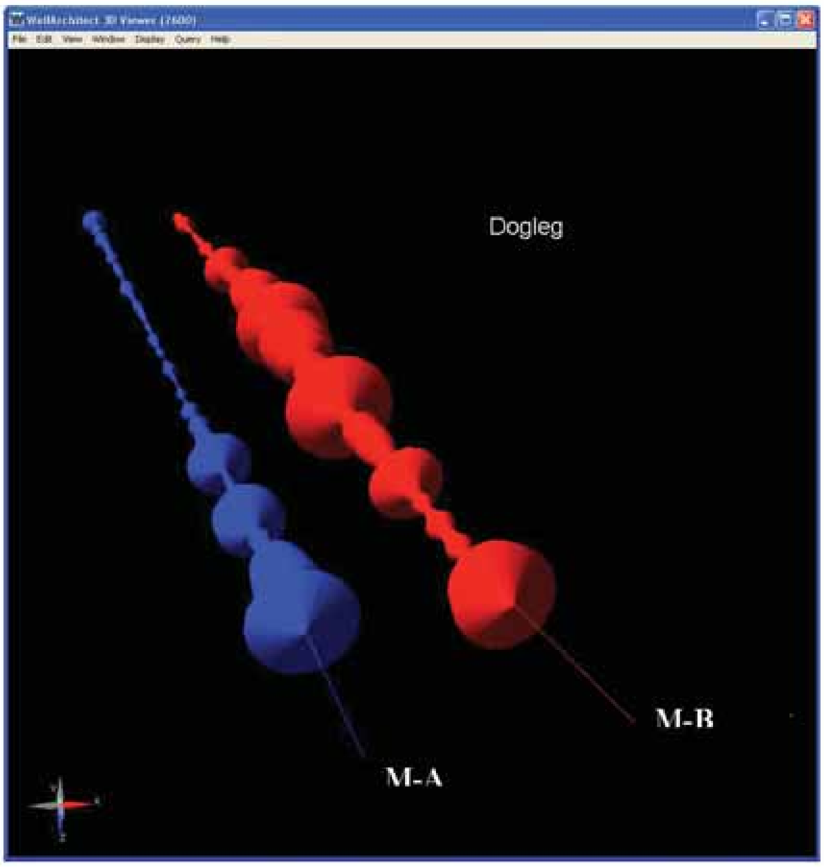


Fig.11

mation tests. This phase of the operation was executed two days before the cement job, considering the long journey ensuring that the testing could be performed in a safe and organized manner without any loss of time. Once the tests were completed, the results were communicated and agreed upon by all involved personnel. The operation involved the setting of the liner hanger and extended conditioning of the mud prior to commencing cementing pumping operations on 17 January 2008 at 18:30 hrs. The preflush and spacer train was pumped followed by cement slurry mixing and pumping on the fly. After the cement was in place at 00.00 hrs, the packer was set and the drillpipe with the running tool pulled out of hole from 9,509 ft (2898 m) to 8,500ft (2591 m). This was done to ensure that the drillpipe was free of cement. After circulating bottoms up, some spacer was recovered at the shakers and the cement job was completed. The cement was placed as per plan in an operation time of 8 hrs 30 minutes vs. a confirmation thickening time of 12 hrs 30 minutes.

Conclusion

The drillers had an array of downhole measurements at their disposal and in the case of the downhole weight on bit and downhole torque, direct comparisons could be made with the rig surface measurements, hence deliver-

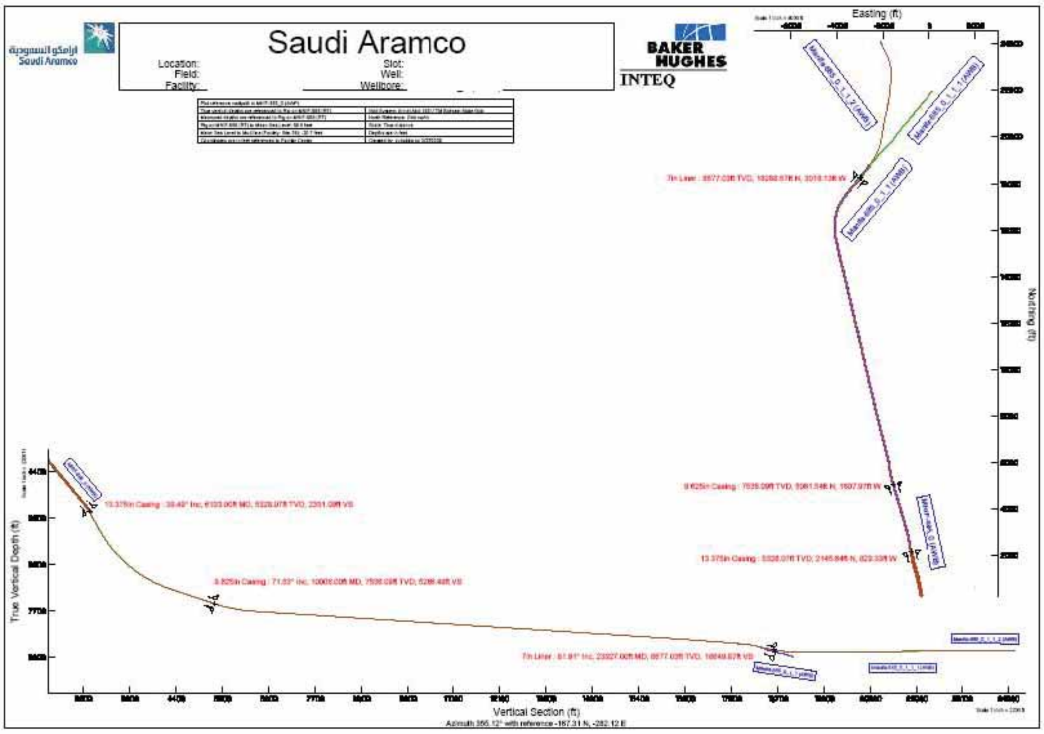


Fig 12

ing an accurate picture of the reigning downhole drilling conditions. Such drilling dynamics tools are employed extensively with RSS tools in horizontal applications to optimize penetration rates while at the same time enabling the drilling crews to manage drilling parameters in search of favourable drilling conditions. The end result was an extremely smooth wellbore. When comparing the wellbore constructed on M-A well with a similar wellbore in M-B well (Fig. 9), we can see just how smooth the wellbore is in relative terms. Additionally, Figs 10 and 11 compare the low dogleg severity maintained in M-A well with that seen in M-B well. Fig. 12 displays the as-drilled well-path for M-A well.

The liner operation and deployment was a success in this well as a result of many factors, including the torque and drag simulation indicating the drag in the well enabled pushing the liner to TD with the need to rotate the liner, which was not an option due to the limit of the casing thread, and the use of the ControlSET liner hanger technology which enables the liner to be washed and circulated to reach bottom. As the project developed one of the main factors of the team effort was to implement new technologies, procedures and lessons and the team approach, the core of this successful implementation, resulted in Saudi Arabia’s longest fully cemented horizontal liner.

Acknowledgments

The authors wish to thank Saudi Aramco, Baker Hughes Inc. and BJ Service Arabia Ltd. for their permission to publish this paper. Appreciation and acknowledgement also go to the whole team involved in helping this project to succeed.

References

1. M. Carrasco- Teja, I.A. Frigaard, SPE, and B. Symour, University of British Columbia; Cementing Horizontal Wells: Complete Zonal Isolation Without Casing Rotation, SPE 114955.

2. S.A. McPherson, SPE, BJ Services Co. Ltd: Cementation of Horizontal Wellbores, SPE 62893.

3. Heisig, G., Sancho, J., Macpherson, J.D.: “Downhole Diagnosis of Drilling Dynamics Data Provides New Level Drilling Process Control to Driller,” SPE 49206, SPE Annual Technical Conference and Exhibition in New Orleans, Sept 27-30, 1998.

4. F. Al-Bani, N. Galindez and P. Carpen, Saudi Aramco; F. Mounzer and D. Kent, Baker Hughes INTEQ: Optimizing Powered Rotary Steering through Better Understanding of the Downhole Environment, IADC/SPE Offshore Technical Conference, Houston, Texas, April 30 – May 3, 2007.

5. SOFTWARE PRODUCT: ADVANTAGE VERSION: 2.10 R0 AUTHORS: Walt Smith, Simon Mantle, Matt Wandstrat, David Niño, Thomas Dahl, Mitch Pinnell, Jane Wolf (Baker Hughes Incorporated).

A New Near-Bit Azimuthal Gamma Ray Tool for Geosteering and Geostopping Applications

By Y. Al-Ansari, S. Abu Faizal, Baker Hughes

Abstract

Placing a horizontal well in the right location and managing it to steer in the sweet spots in thin reservoirs is always a challenge in a geosteering job. While drilling, casing point identification is crucial in areas where gas cap or total-loss zones are expected. Excessive penetration into these reservoirs can pose Health, Safety and Environmental as well as economic risks. In such complex drilling conditions, close-to-bit LWD measurements are advantageous for early formation identification and increasing the ability to keep the well within thin reservoir intervals.

This paper discusses the newly developed 4¾ and 9½ Near-Bit Gamma (NBG) tool with azimuthal imaging. The new NBG tool is run in conjunction with a Rotary Steerable System (RSS) which is well suited to geosteering applications. Gamma-Ray readings in this tool are 6-11 ft behind the bit in the RSS – Near-Bit-Gamma Bottom Hole Assembly compared to 50+ ft in a conventional RSS assembly, thus enabling early identification of formation changes.

Two field examples are presented discussing the successful application of 9½ NBG for geostopping. One of the case studies is from a Middle-Eastern carbonate oil field, and the other from a clastic reservoir in North-Sea. In both examples the use of 9½ NBG tool for Geostopping not only saved the client the expensive use of LWD tools but also reduced HSE and other economic risks.

Introduction

Landing the drilling assembly in the target horizon, maintaining the well bore in the zone of maximum interest and predicting reservoir exit remain real challenges to the oil industry. Right decisions made while drilling by expert recommendations from drilling and geosciences are key to helping overcome this challenge. Close-to-bit measurements are an essential factor in building those decisions (Prillman et al, 1995).

Gamma ray measurements serve as a good lithology indicator in differentiating shale/non-shale by measuring the natural gamma emission of radioactive elements in the formation (generally from clays). Over the years, the LWD Gamma Ray measurement has been extensively used in geosteering applications. In combination with azimuthal information, the Gamma tool is extremely useful in supporting geosteering, even in challenging thin reservoirs (Pitcher et al, 2009).

It is important for this tool to be as close as possible to

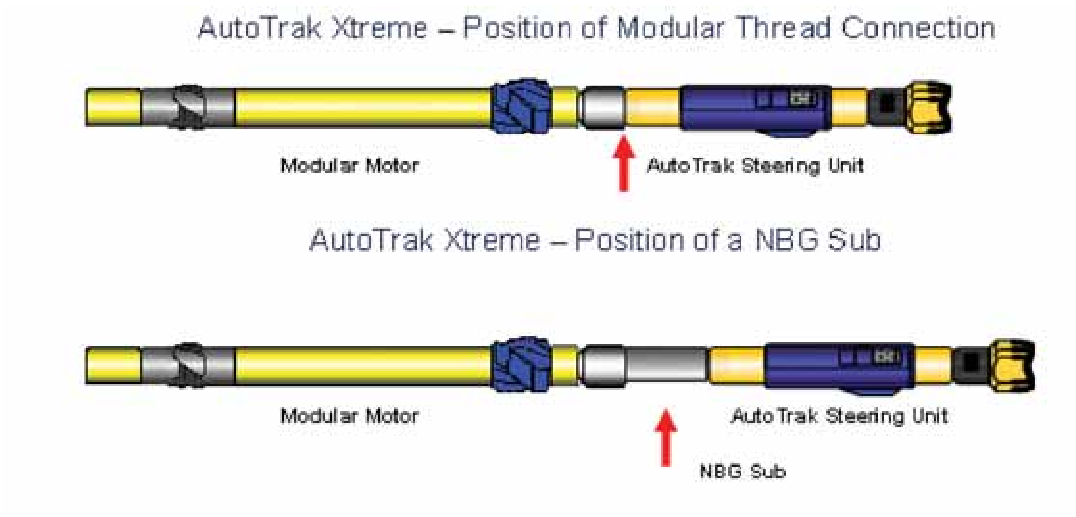


Fig 1. Near-Bit Gamma sub placed within the AutoTrak BHA.

the bit to assist in early detection of the reservoir entry or exit to maximize the productive well interval in complex geological formations. It also helps maximize the productive reservoir length by precise casing point section. This paper discusses a new 4¾ and 9½ azimuthal Near-Bit Gamma built into an AutoTrak steering unit for the purpose of improving reservoir navigation in horizontal wells.

One of the advantages of measurements taken right at the bit is the ability to perform geostopping. This involves recognizing marker beds almost as soon as the drill bit penetrates and to stop drilling precisely at casing or coring points. In this paper, a field example is presented for a successful application of 9½ Near-Bit Gamma Ray (NBG) with a Rotary Steerable System (RSS-AutoTrak) for early detection of formations in one of the oil fields in the Middle East. The objective was to pick the casing point for the 12¼″ section as close to the top as possible of a limestone member (target zone), where a gas cap is expected. The target zone is a limestone reservoir overlain and sealed by an Anhydrite horizon. Drilling the 12 ¼″ section too far into the target zone may result in total drilling fluid losses or exposing the gas cap, which are both well control and HSE hazards.

Tool Assembly and Measurements

The near-bit azimuthal Gamma Ray tool with steering unit is available for 9½ and slim 4¾ sizes. The integral rotary steerable system (AutoTrak) and the Near-Bit Gamma sub are depicted in Figure 1. The system is particularly suited for motor-powered "AutoTrak X-treme" BHAs in which the motor is used to deliver additional power and speed to the bit to increase drilling reach and performance.

The control Gamma sub is positioned between the AutoTrak Steering unit and its hydraulic pump assembly. The Gamma sub houses Near-Bit Gamma sensor, azimuthal Gamma sensors and tri-accelerometers (Figure 2). In the 4¾ and 9½ assemblies these subs are 6ft and 11ft respectively from bottom of tool.

Accelerometers provide measurements of inclination and most computation of tool face. The inclination measurement is of the sensor housing drill collar, the accuracy of which exceeds sonde based sensors. The Gamma detectors consist of NaI crystals coupled with photomultiplier tubes. There are two detectors which are subwall mounted and positioned 180° relative to one another. The sensors provide azimuthal measurements of natural Gamma Rays with individual sensitivities exceeding typical MWD sonde based detectors. Close proximity to the bit provides information on the directional behavior of the steerable BHA in a more timely manner. Additionally, the use of the inclination measurement, coupled with BHA prediction algorithms, provides a more accurate definition of the well path (Meyer and

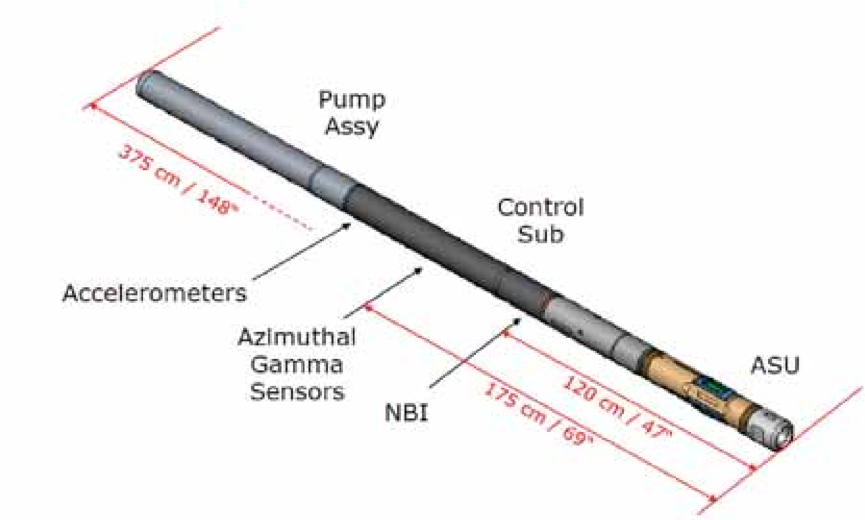


Fig 2. 4¾" AutoTrak Gamma System Overview.

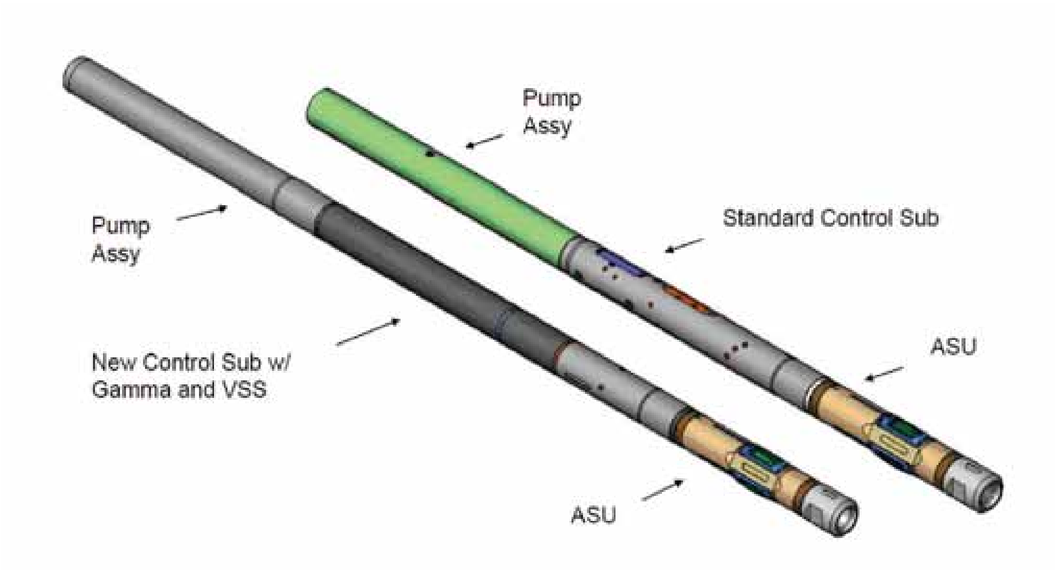


Fig 3. AutoTrak with Gamma versus Standard AutoTrak.

Wu, 1994). The Near-Bit sensor module communicates with the MWD in real-time, without any restrictions, via the hard-wired modular motor.

Figure 3 shows both a standard AutoTrak and AutoTrak houses part of the Gamma sub. The Near-Bit Gamma sub consists of a top electronics sub, a sleeve covering the Gamma detectors and electronics and bottom sub. It features high torque connections up and down at each end (Figure 4). The position of the gamma sensors within the steering unit reduces their distance from the bit.

As part of an AutoTrak rotary steerable BHA, the Near Bit Gamma service provides formation Gamma ray measurements close to the bit. This enables rapid identification of geological targets, allowing early confirmation that the zone of interest has been entered, which is important for wellbore stability. It will also help in early detection of reservoir entry or exit to help maximize the productive well interval in complex geological formation. Likewise, precise casing point selection to maximize the productive reservoir length by reducing the cased-off interval. Additionally, the Near-Bit Gamma service provides real-time axial and lateral vibration and stick-slip measurements close to the bit. The Gamma sensor operates with oil-based and water-based drilling fluids.

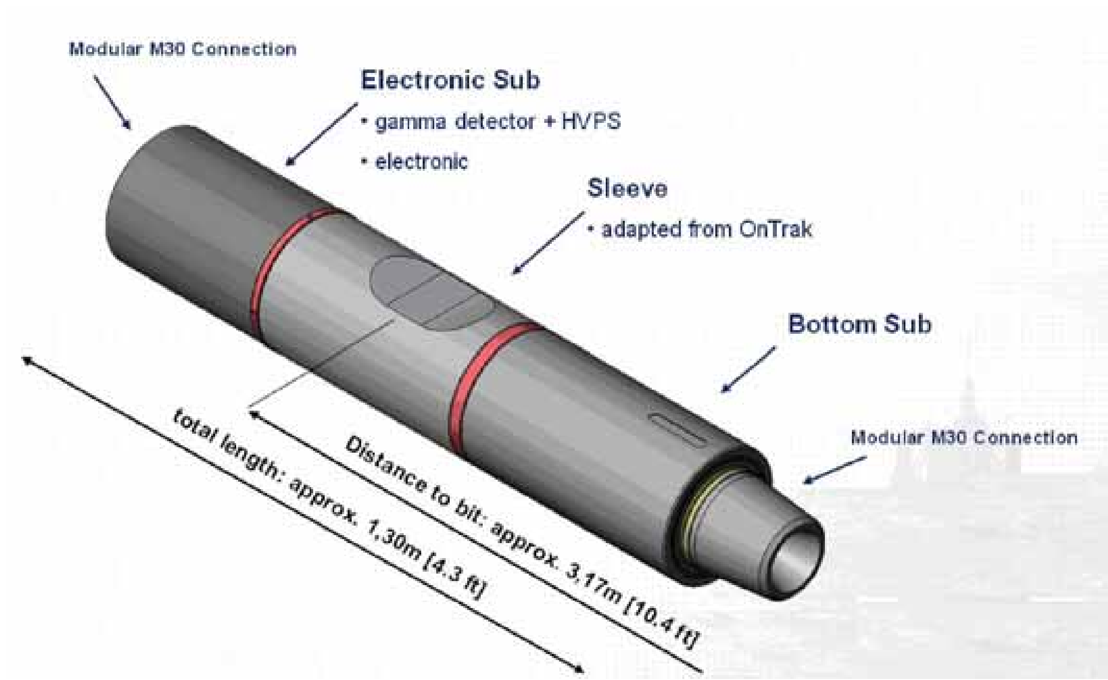


Fig 4. 9 ½ Near Bit Gamma Sub overview.

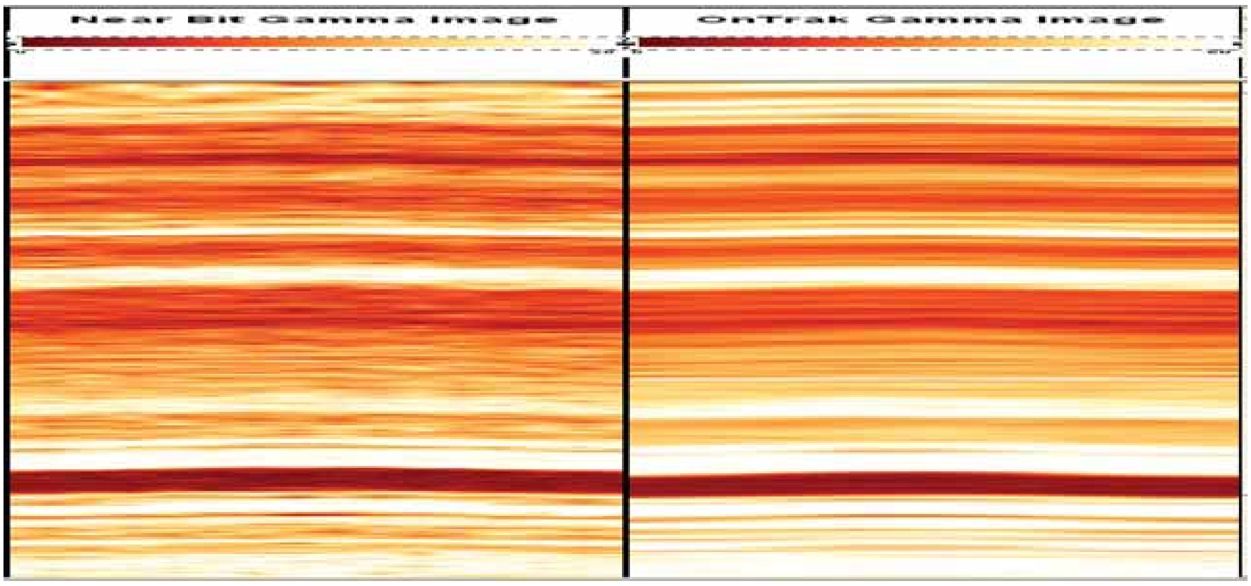


Fig 5. Comparison of real-time image log from OnTrak and Near Bit Gamma 44¾”¼ tools from one of the wells in gas field

The azimuthal gamma service uses the two gamma detectors positioned 180° apart which acquire counts as the tool rotates. Combining count rates from two detectors improves precision statistics and provides redundancy. A magnetometer within the tool senses components of the earth's magnetic field relative to the tool orientation, enabling gamma counts to be divided into sixteen azimuthal sectors (numbered 0 to 15). Sectors are oriented to the tool-face using inclination and azimuthal information from the MWD platform being run with the tool (e.g. MPR, OnTrak). High frequency tool-face updates allow the sectoring process to function at rates of up to 400 rpm. While rotating, the gamma counts detected in each sector are binned over a defined acquisition time. Counts are divided by the time per sector in order to obtain a value for counts per second. Figure 5

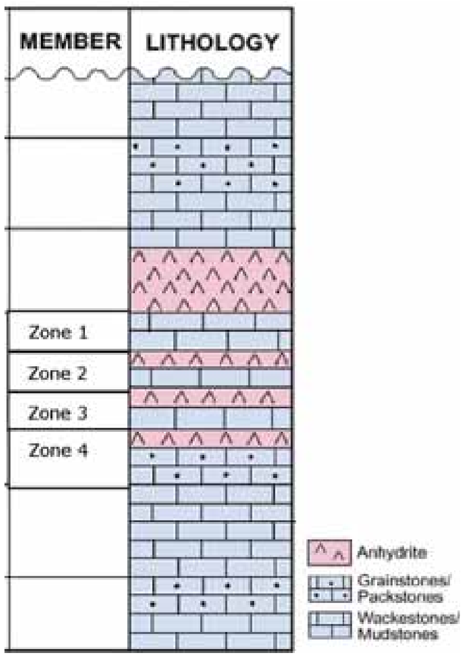


Fig 6. Generalized stratigraphic column representing target formation and its members

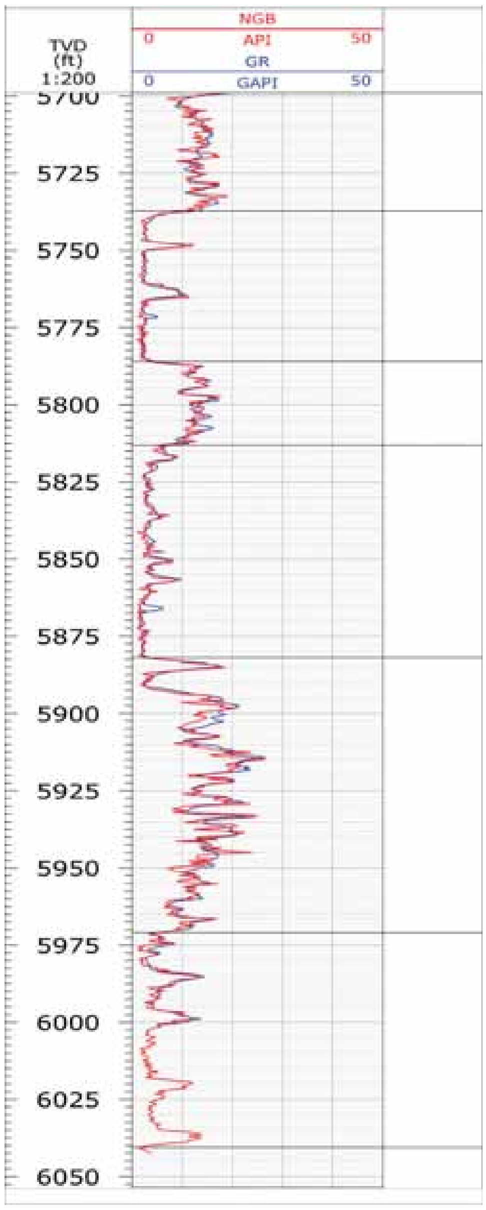


Fig 7. Gamma Ray reading from Near-Bit Gamma and OnTrak tool

illustrates the 4¾″ Near Bit Gamma image acquired ~ 5 ft from the bit in a Middle-Eastern gas field.

Geostopping Application

Middle-Eastern case study

The field discussed here is one of the main sources of the oil in the Middle East. The field is a relatively thick limestone formation which consists of four geographically widespread carbonate members which are separated by layers of anhydrite (Figure 6). Two of the lower members are the only members with commercial production of oil and are considered to be the main target for most wells.

The plan was to set 9⅝″ casing at the top of lowest limestone member (target zone) in order to utilize LWD measurements in the subsequent section to characterize the gas cap zone. The operational scope was to detect the top seal formation (anhydrite) by utilizing less expensive Gamma Ray measurements in the 12¼″ hole section instead of running with a complete LWD suite which was to be used in the next section. The challenge was to drill this section in one run with only Gamma Ray services saving the client at least one day of onshore rig operations with the minimal cost services required for Geostopping at the top of target zone to set the 9⅝″ casing.

The process of Geostopping the well on top of the target zone involved LWD operations and geoscience teams with correct geosteering tool selection. A 9½″ Near Bit Gamma tool was selected to provide the real-time formation evaluation data with the AutoTrak.

Figure 7 shows the real time gamma ray responses from NBG and OnTrak tools. A very low gamma reading in real-time (Fig. 7) immediately above the target zone indicates touching of the anhydrite which is the seal of the reservoir. Gamma ray responses from offset well models were used extensively as reference while entering the target zone. Figure 8 shows the reservoir navigation model built using the GR from offset wells. Correlating the

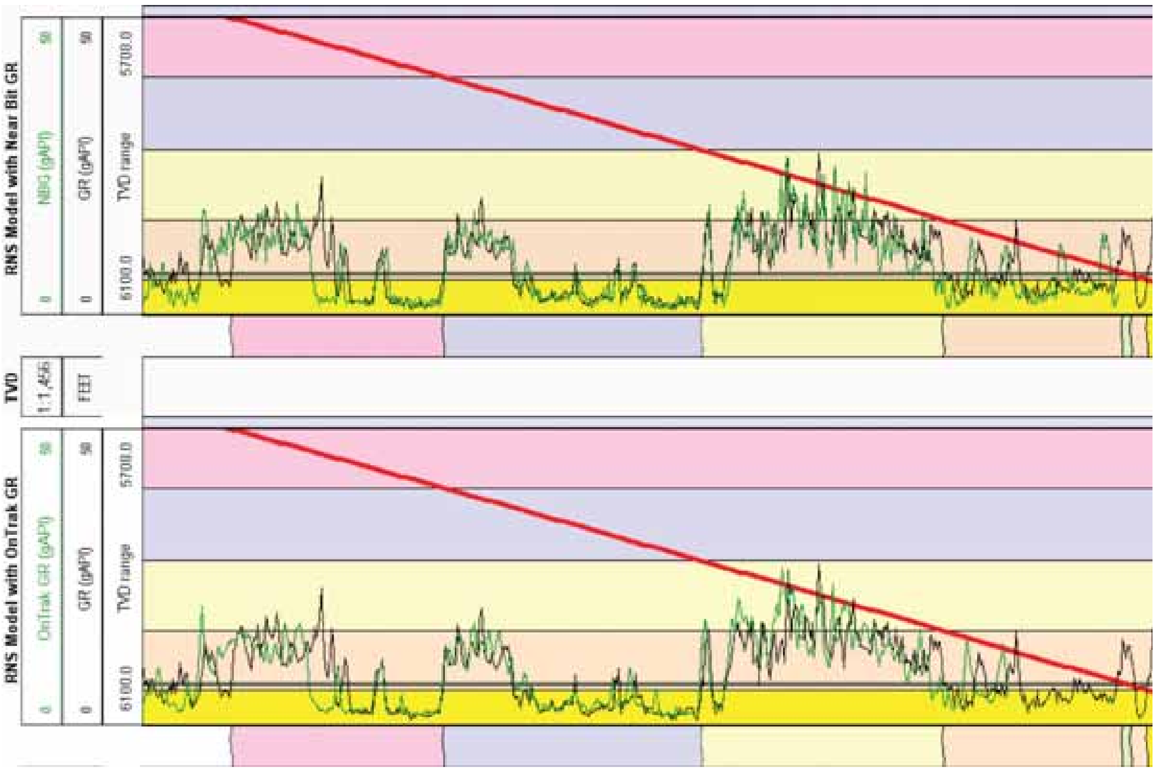


Fig 8. Reservoir navigation model for geostopping on top of Target Zone using Gamma Ray from Near-Bit Gamma and OnTrak tools

Near Bit Gamma with the offset well model, the entry of the formation was confirmed and the 9⅝″ casing was set. Using the NBG in combination with AutoTrak with the logging data transmitted in real time, this section was drilled successfully and safely in one run with less cost compared to using LWD tools used for the whole section.

The Near Bit Gamma sensor in this arrangement is 11 ft from the bit while the normal gamma offset with a standard tool is usually around 51 ft. Thus the design of the near-bit gamma sub is extremely beneficial for early formation identification which is critical in geostopping applications. Figure 7 clearly shows the advantage of having the gamma ray reading close to the bit compared to gamma ray in the standard tool by detecting the formation early allowing true real-time decisions.

North-Sea case study

A recent geostopping application was successfully implemented in a North Sea gas field. The target formation is predominantly shale and claystone with sandstone at the top of the gas reservoir. The objective was to drill an optimal 12¼″ (with a 13½″ underreamer) horizontal well with good ROP. Geostopping early was required to identify the casing point at the top of the reservoir and save time by minimizing drilling with cutting samples and gas response for reservoir confirmation.

The BHA consisted of OnTrak, AutoTrak system, and a Near-Bit Gamma Ray. Figure 9 shows the excellent correlation between the OnTrak and the Near-Bit Gamma Ray response. The NBG helped the client to detect the casing point (Figure 9) with minimum exposure of the reservoir. Additionally, with integration of AutoTrak the complete section was drilled with one single run with zero HS&E incidents and with an average ROP of 53 ft/hr in a total of 242 circulating hours including the wiper trip.

Summary and conclusion

The new technology of Near-Bit Gamma measurements has proved very beneficial to operators in geosteering and Geostopping application. New azimuthal Near Bit Gamma sensors have been built into an AutoTrak

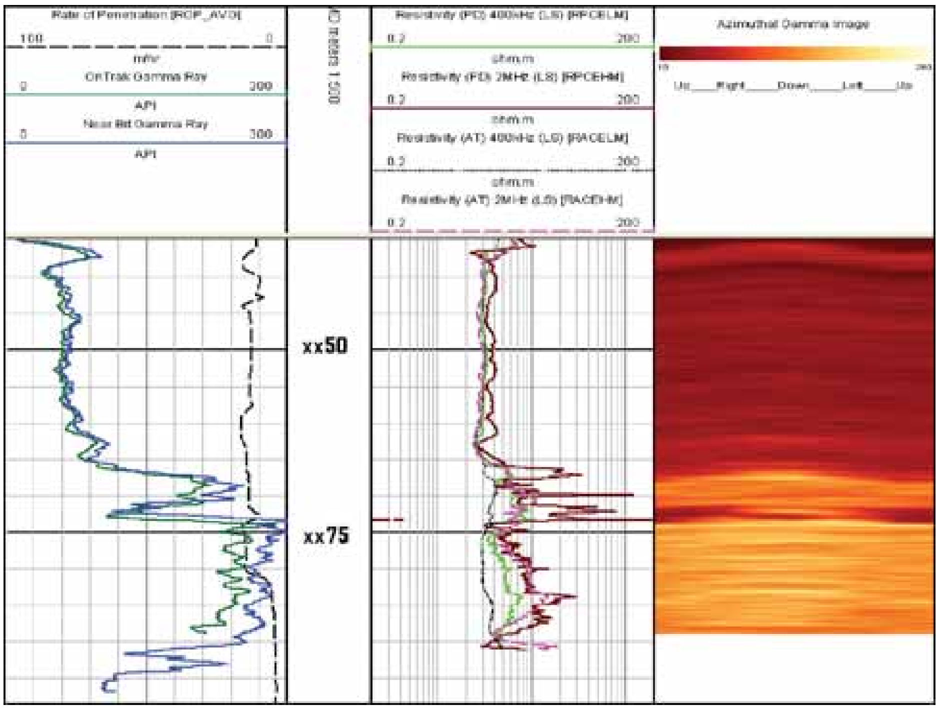


Fig 9. Use of NBG for early detection of reservoir sands.

steering unit for the purpose of improving reservoir navigation in horizontal wells. With the azimuthal capability, the tool can maximize the productive well interval by early detection of the reservoir entry or exit in thin formations, also providing formation true dip.

Field examples successfully proved the need for Near-Bit Gamma services for Geostopping applications. NBG helped the client in the early detection of formation changes and formation identification for precise selection of casing points there by saving cost and avoiding major HS&E risks.

Acknowledgements

The authors would like to thank the Baker Hughes team for their efforts in tool deployment and job support.

References

Prillman, J.D., Allen, D.F and Lehtonen, L.R., 1995. Horizontal Well Placement and Petrophysical Evaluation Using LWD. SPE 30549 presented ATCE held in Dallas, USA, 22-25 October.

Pitcher, J., Schafer D. and Botterell, P., 2009. A New Azimuthal Gamma at Bit Imaging Tool for Geosteering Thin Reservoirs. SPE 118328 presented at SPE/IADC Drilling Conference and Exhibition held in Amsterdam, The Netherlands, 17-19 March

Meyer, W.H., Wu, J.Q., Macune, D.T. and Harvey P.R., 1994. Near-Bit Propagation Resistivity for Reservoir Navigation. SPE 28318 presented in Annual Technical Conference and Exhibition held in New Orleans, LA: 25-28 September

Prediction of Poisson's Ratio and Young's Modulus Parameters for Hydrocarbon Reservoirs using Artificial Neural Networks

By Bandar Duraya Al-Anazi, King Abdulaziz City for Science and Technology, Oil and Gas Center, Mohsen Saemi, Research Institute of Petroleum Industry (RIPI), and Ammal Al-Anazi, Saudi Aramco

ABSTRACT
Determination of rock elastic properties plays an important role in various geomechanical applications such as hydraulic fracture design, sand production control and wellbore stability analysis. These elastic properties are often reliably determined from laboratory tests on cores extracted from wells under simulated reservoir conditions. Unfortunately, these tests are expensive, time consuming and most of the wells have limited core data. On the other hand, logs are often available and provide a continuous record compared to cores where only discrete values are obtained. Empirical equations are used to estimate elastic properties from logs however empirical corrections must be performed to calibrate the dynamic calculation to core-measured values. Due to the complexity of the reservoirs, these models may not be of practical use and consequently extensive data preprocessing and understanding of the geology of the region and the tool limitations are required. Alternatively, artificial neural network has the potential to model complex nonlinear underlying dependency between high dimensional input logs and elastic properties.

The potential of the neural network has been demonstrated by developing Poisson's ratio and Young's modulus interpretation models in a hydrocarbon reservoir using log-based density and acoustic measurements and core-measured porosity, minimum horizontal stress, pore pressure and overburden stress. Learning and prediction performance was performed using correlation coefficient, root mean squared error, absolute average error and maximum absolute error. The result shows that artificial neural network can successfully be used to construct elastic interpretation models that can be employed to interpret new input data with a minimum error rate.

Keywords: Poisson's ratio, Young's modulus, Logs, Core, Artificial intelligence

Introduction
Mechanical properties usually, of concern for treatment design and analysis, are (1) elastic properties, such as Young's modulus (or shear modulus) and Poisson's ratio; (2) strength properties, such as fracture toughness, tensile and compressive strength; (3) poroelastic parameters describing the compressibility of the rock matrix compared with the compressibility of the bulk rock under specific fluid flow (or migration) conditions. Stress not only controls or influences most aspects of fracture behavior, but also influences the values of both reservoir properties and mechanical properties of the rock. For example, increased confining stress will generally result in increased strength, decreased permeability and porosity, and mixed results for Young's modulus and Poisson's ratio (2).

Rock mechanics is the science dealing with the theoretical and applied behavior of rock due to either external natural or man made stresses. Traditionally, rock mechanics are widely used by civil as well as mining engineers. Recently, rock mechanics has been applied to solve problems in many aspects of petroleum engineering such as drilling, reservoir and production engineering. In the following sections, light will be shed on the involvement of rock mechanics on solving the many problems that may be encountered during the various petroleum engineering activities such as drilling, reservoir, and production engineering.

Various rock properties are required as an input in any attempt to solve various engineering problems. It is obvious that rock mechanical testing of cores must be designed according to the purpose of the investigation. If the objective is to predict borehole instability, then the testing procedures may not be the same as for example in reservoir compaction.

These outlined testing procedures were set to minimize human errors. Rock mechanical data are obtained either by testing representative rock samples in laboratory or by analyzing field records. Triaxial testing of rock samples provides important data such as failure criteria, frictional properties, apparent cohesion and angle of internal friction, and arid elastic properties (Young's modulus, bulk modulus, Poisson's ratio, etc.). Many other properties can be measured based on rock testing such as, pore and bulk compressibility, permeability stress sensitivity, crushing resistance, P & S velocities, swelling, etc. (4).

Details of these tests can be found in any professional rock mechanics. Field data may provide us with formation lithology, continuous record of formation porosity (as an indication of rock strength), formation fluids analysis, reservoir geology, etc. (Table 1). Well logs provide continuous data versus depth, but do not measure directly the parameters that are needed for a rock mechanical analysis. Rock mechanics have been used to investigate and solve several problems in the oil industry as illustrated in Table 2.

Measurement of Poisson's Ratio and Young's Modulus

The two main elastic constants which are usually used in most rock failure models are Poisson's ratio and Young's modulus. Young's modulus is the measure of the stiffness of the rock material, i.e. the sample resistance against the compressive stress (load). Poisson's ratio is a measure of the simultaneous change in elongation and in cross-sectional area within the elastic range during a tensile or compressive test. Elastic constants are evaluated from the stress versus lateral and axial strains measured in conjunction with the triaxial compressive testing. Elastic constants can be estimated from using the following equations [1 and 2]:

$$E=\left[\frac{\sigma_{z1}-\sigma_{z2}}{\xi_{z1}-\xi_{z2}}\right] \qquad \ldots(1)$$

$$\nu=\left[\frac{\xi_{x1}-\xi_{x2}}{\xi_{z1}-\xi_{z2}}\right] \qquad \ldots(2)$$

The parameters shown in equation 2 are measured on laboratory using strain gauges attached to test sample during the unconfined compressive strength.

A hydraulic fracture will propagate perpendicular to the minimum principal stress ($\sigma 3$). If the minimum horizontal stress is $\sigma 3$, the fracture will be vertical. Minimum horizontal stress profile with depth can be computed using Eq. 3.

• Uniaxial tensile and compressive strength.
• Triaxial compressive strength and failure criteria.
• Cement-casing and Cement-formation bond strength.
• Direct and indirect shear strength.
• Permeability stress sensitivity.
• Elastic and Frictional properties.
• Matrix and pore compressibility.
• P & S velocities.
• Propant crushing resistance.
• Swelling and wet/dry rock strength.

Table 1. Type of rock mechanical tests.[2]

Phase	Problem	Potential solutions	Data required
Drilling Engineering	Borehole instability	-changing mud weight. -selecting mud type. -controlling mud cake efficiency. -managing well orientation.	-rock elastic properties. -rock failure criteria. -in-situ stress stale. -rock swelling characteristics. -well orientation. -well inclination. -drilling fluid properties. -mud cake efficiency.
Production Engineering	Sand production Perforation stability Fracturing height and orientation Water injection	-selecting perforation location -selecting completion type. -controlling fluid drawdown. -controlling production rate. -managing proppant crushing resistance. -selecting proppant type. -selecting fracturing fluid type. -measuring rock compressibility. -controlling injection rate. -controlling water temperature. -testing water-rock compatibility. -controlling injection rate.	-rock elastic properties. -rock failure criteria. -in-situ stress state. -rock swelling characteristics. -well orientation -well inclination. -reservoir description.
Reservoir Engineering	Reserve Calculation Compaction Subsidence Reservoir stress sensitivity	-selecting well location. -controlling production rate -controlling injection rate.	-rock elastic properties. -rock failure criteria. -in-situ stress state. -rock swelling characteristics. -well orientation. -well inclination. -reservoir description. -permeability sensitivity to stress.

Table 2. Implementation of rock mechanics in solving petroleum engineering problems (afer Al-Awad, 1998).

$$\sigma_{min} = \frac{\upsilon}{1-\upsilon}(\sigma_{ob} - \alpha\ \sigma_p) + \alpha\ \sigma_p + \sigma_{ext} \text{ ....(3)}$$

Poisson's ratio can be estimated from acoustic log data or from correlations based upon lithology. The overburden stress can be computed using density log data. Normally, the value for overburden pressure is about 1.1 psi per foot of depth. The reservoir pressure must be measured or estimated. Biot's constant must be less than or equal to 1.0 and typically ranges from 0.5 to 1.0. The first two terms on the right hand side of Eq 3 represent the horizontal stress resulting from the vertical stress and the poroelastic behavior of the formation. The tectonic stress term is important in many areas where plate tectonic or others forces increase the horizontal stresses [2, 7, 8].

Poroelastic theory can be used to determine the minimum horizontal stress in tectonically relaxed areas. It combines the equations of linear elastic stress-strain theory for solids with a term that includes the effects of fluid pressure in the pore space of the reservoir rocks. The fluid pressure acts equally in all directions as a stress on the formation material. The "effective stress" on the rock grains is computed using linear elastic stress-strain

Lithology	Young’s Modulus, Pa
Soft Sandstone	$1.3 - 3.4 \times 10^{10}$
Hard Sandstone	$4.1 - 6.9 \times 10^{10}$
Limestone	$5.5 - 8.3 \times 10^{10}$
Coal	$0.7 - 7 \times 10^{9}$
Shale	$0.7 - 7 \times 10^{10}$

Table 3. Ranges of Young’s Modulus for various lithologies.[9]

Lithology	Poisson's ratio
Saturated clay	0.4 to 0.5
Rock	0.1 to 0.4
Sand, gravelly sand	0.3 to 0.4
Silt	0.3 to 0.35
Sandy clay	0.2 to 0.3

Table 4. Ranges of Poisson’s Ratio for various lithologies.[20]

theory. Combining the two sources of stress results in the total stress on the formation, which is the stress that must be exceeded to initiate fracture. [2,7,8]

In addition to the in-situ or minimum horizontal stress, other rock mechanical properties are important when designing a hydraulic fracture. Poisson’s ratio is defined as “the ratio of lateral expansion to longitudinal contraction for a rock under a uniaxial stress condition”.[9] The value of Poisson’s ratio is used in Eq. 3 to convert the effective vertical stress component into an effective horizontal stress component. The effective stress is defined as the total stress minus the pore pressure.

The theory used to compute fracture dimensions is based upon linear elasticity. To apply this theory, the modulus of the formation is an important parameter. Young’s modulus is defined as “the ratio of stress to strain for uniaxial stress”. [9] The modulus of a material is a measure of the stiffness of the material. If the modulus is large, the material is stiff. In hydraulic fracturing, a stiff rock will result in more narrow fractures. If the modulus is low, the fractures will be wider. The modulus of a rock will be a function of the lithology, porosity, fluid type, and other variables. Table 3 and 4 illustrates typical ranges for Young’s modulus and Poisson’s ratio as a function of lithology.

Multilayered Perception (MLP) Neural Networks

Artificial Neural Networks (ANN) performs learning using a class of nonlinear optimization techniques without the need for a priori selection of the mathematical model. Instead, the underlying relationships between input and output variables are determined automatically which indicates that ANN is well suited for problems whose exact functional form is unknown or difficult to discover. Since geosciences data suffers complexity and scarcity ANN has been applied to many applications in petroleum industry. ANN is an adaptive, parallel information processing system which is able to develop associations, transformations or mappings between objects or data. It can be used to find a mathematical model that relates multidimensional input data to outputs, i.e., it might be regarded as a multivariate regression tool. The basic idea is to present ANN with training data set that will supervise the adjustment of the network parameters in the form of a weight matrix.[17] The learning algorithm that is commonly applied and the one used for this study is called back propagation.[18] The training is performed by propagating the inputs from the input layer, through all the hidden layers, and finally the network provides its output which is different from the known target output. The training process estimates the weight matrix by minimizing a quadratic error. The calculated error is then propagated backwards through the network and the weights are automatically adjusted. Three network layers were selected where hidden neurons were automatically optimized. The learning algorithm, Nguyen-Widrow algorithm, was used to select the initial range of starting weight values and the conjugate gradient algorithm was used to optimize the weights. In order to avoid over fitting the data and consequently give poor prediction performance, cross validation was used to select the best model. The ANN technique has several advantages over conventional traditional techniques. The most important one is its ability to mimic complex non-linear models without a priori knowledge of the underlying model that it is free from the constraints of a specification of structural relationships between inputs and outputs.[19]

This network consists of one input layer, one output layer and one or several hidden layers. Term of Bias in any layer is analogous to the constant term of a polynomial.

Number of neurons in input and output layers depends on number of input and output parameters and number of neurons in hidden layer may be equal to zero or something. All layers are connected together and strength of this inter-connection depends on their along weight. Output form of neuron in hidden layer is a transformation of sum output weights of input layers as below:

$$Z_j = g\left(\sum_{i=1}^{d} W_{ji} P_i\right) \qquad (4)$$

Output form of neuron in output layer is a transformation of sum output weights of hidden layers as below:

$$q_k = \tilde{y}\left(\sum_{j=1}^{m} \tilde{W}_{ki} Z_i\right) \qquad (5)$$

Where Pi is the ith output from the input layer, Zj is the jth output from the hidden layer, Wij is the weight in the first layer connecting neuron i in the input layer to neuron j in the hidden layer, is the weight in the second layer connecting neuron j in the hidden layer to the neuron k in the output layer and g, are the transformation functions.

Transformation function is usually a function as follow:

$$g(a) = \tanh a = \frac{\exp(a) - \exp(-a)}{\exp(a) + \exp(-a)} \qquad (6)$$

Or:

$$g(a) = \frac{1}{1 + \exp(-a)} \qquad (7)$$

In order to design artificial neural network, the related experimental data should be used. So, experimental data are divided to three groups of training, validating and testing. Training data are used for determination of optimum amounts of the model (above correlations), testing data are used for checking of training, and finally validating data are used for study of model accuracy. Parameters of above correlations are obtained by training of artificial neural network. A trained network can enter input parameters into input layer and any layer implements the calculation by above correlations and the network output is obtained by last layer operation. some criteria such as: maximum number of epochs, training time, Root Mean Square Error (RMSE), Absolute fraction of variance (R2), coefficient of variation, pearson product moment correlation coefficient, Mean absolute error (MAE) are considered to stop of training. The above parameters are defined as follows:

$$RMSE = \left[\frac{1}{P}\sum_{j=1}^{L}\left|\frac{O_j - t_j}{L}\right|^2\right]^{1/2} \qquad (8)$$

$$R^2 = 1 - \left(\frac{\sum_j (t_j - O_j)^2}{\sum_j (O_j)^2}\right) \qquad (9)$$

$$COV = \frac{RMS}{O_{mean}} \times 100 \qquad (10)$$

	Max	Min	Ave	SD
Depth , m	3703	3611	3657	26237
Porosity, %	21	0	4.1	3.9
RHOB, g/cm3	2.98	2.312	2.68	0.113
DT Compression , µs/m	258.92	145.43	168.06	17.20
DT Shear, µs/m	452.9	240.03	312.15	29.65
Poisson's Ratio	0.374	0.178	0.292	0.032
Young's Modulus, Pa	9.9×10^6	2.57×10^6	6.41×10^6	1.2×10^6
Overburden Stresses, Pa	9.1×10^7	8.86×10^7	8.97×10^7	0.65×10^6
Pore Pressure, Pa	5×10^7	5.18×10^7	5.2×10^7	77814
Minimum Horizontal Stress, Pa	7784	5667	7121	404

Table 5. Properties of rock mechanics data used in the study.

R^2	AARE, %	ARE, %	
0.992	0.9895	-0.0086	Poisson's Ratio
1	0.00056	0.01917	Young's Modulus

Table 6. Error analysis of the proposed and investigated Poisson's Ratio & Young's Modulus models.

Where t is objective, O is output, P is pattern, and Omean is average output. In next section, the model in this study will be discussed.

Results and Discussion

In this study, there are 601 data points that are obtained. these include porosity measurement from Laboratory, RHOB log, DT Compression from Dipole sonic Imager (DSI),DT Shear from DSI, Overburden Pressure calculated from Density log and geological logs, Pore Pressure from Modular Formation Dynamics Tester (MDT) and Repeat Formation Tester (RFT) tools, Minimum Horizontal Stress obtained from Leak-off Tests, Young's Modulus and Poisson's Ratio as a result of DSI. Table 5 shows the statistics of all variables used for training and testing the model and Table 6 shows the error Analysis of The Proposed and Investigated Poisson's Ratio & Young's Modulus Models.

Random data points were selected to train and validate the model and another data used for testing purpose. The created model use the Core Porosity, RHOB, DTc, DTs, Overburden Pressure, Pore Pressure and Minimum Horizontal Stress as input parameters to estimate the Young's Modulus and Poisson's Ratio as output results. Figure 1 shows the progress of training that the model with the least momentum rate has reached to the greatest performance (or least MSE) at 293 epochs. Figure 1 shows the progress of training.

All data were preprocessed by normalizing their standard deviation and performing principal component-analysis using a maximum fraction of 0.001 (21). The targets are also normalized using standard deviation. For the presented study, several different network structures with different neurons and layers have been investigated, and the optimum structure was selected which uses the tan-sigmoid transfer function in the hidden layer and linear transfer function in the output layer. In this model, 14 neurons have been used in the hidden layer. The resulting network has two output neurons since the target vector has two elements. The default Levenberg-Marquardt algorithm is used for training .Figure 2 shows the structure of the model.

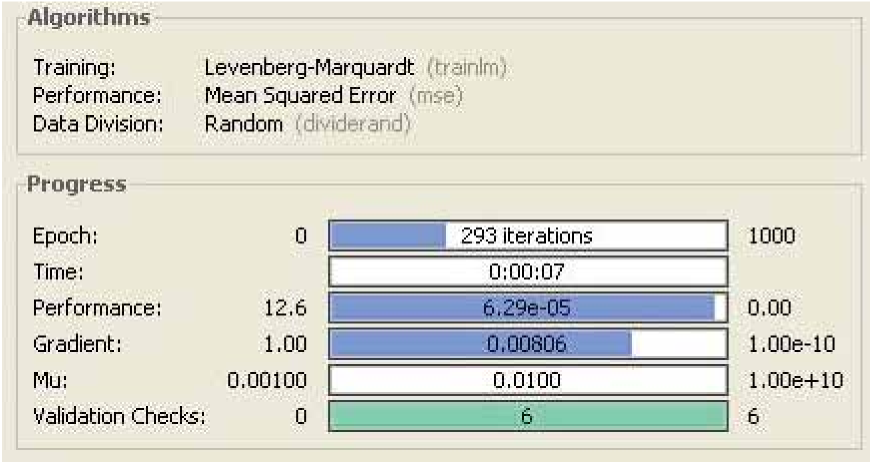


Figure 1 shows the process of training.

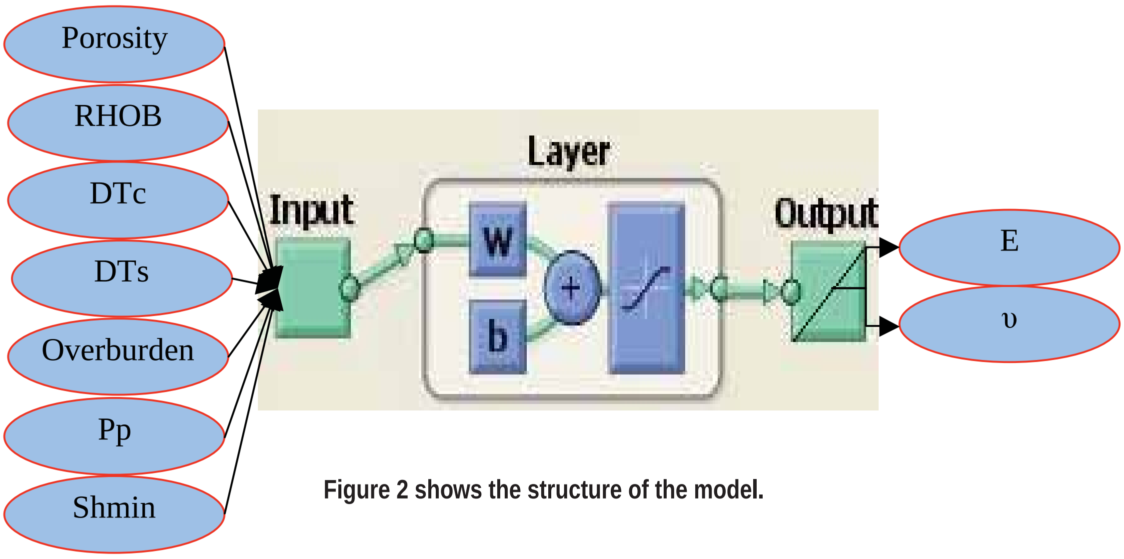


Figure 2 shows the structure of the model.

The training stopped after 293 iterations because the validation error increased. Figure 3 shows the training and testing performance. The result here is reasonable since the test set error and the validation set error has similar characteristics, and it doesn't appear that any significant over fitting has occurred.

The next step is to perform some analysis of the network response. The entire data set was put together through the network (training, validation, and test) and a linear regression between the network outputs and the corresponding targets was performed. The two outputs seem to track the targets exactly very well and the R-values for Young's Modulus is 1 and for Poisson's Ratio is 0.99. Figure 4 shows the relationship between real and predicted Young's Modulus also Figure 5 shows the relationship between real and predicted Poisson's Ratio

Conclusions

An attempt has been made in this work to develop an ANN for elastic parameters prediction with a non-linear relationship and mapping between the petrophysical and geomechanical data and elastic modals. It has been shown that a three layer Network gives the best prediction of elastic properties.

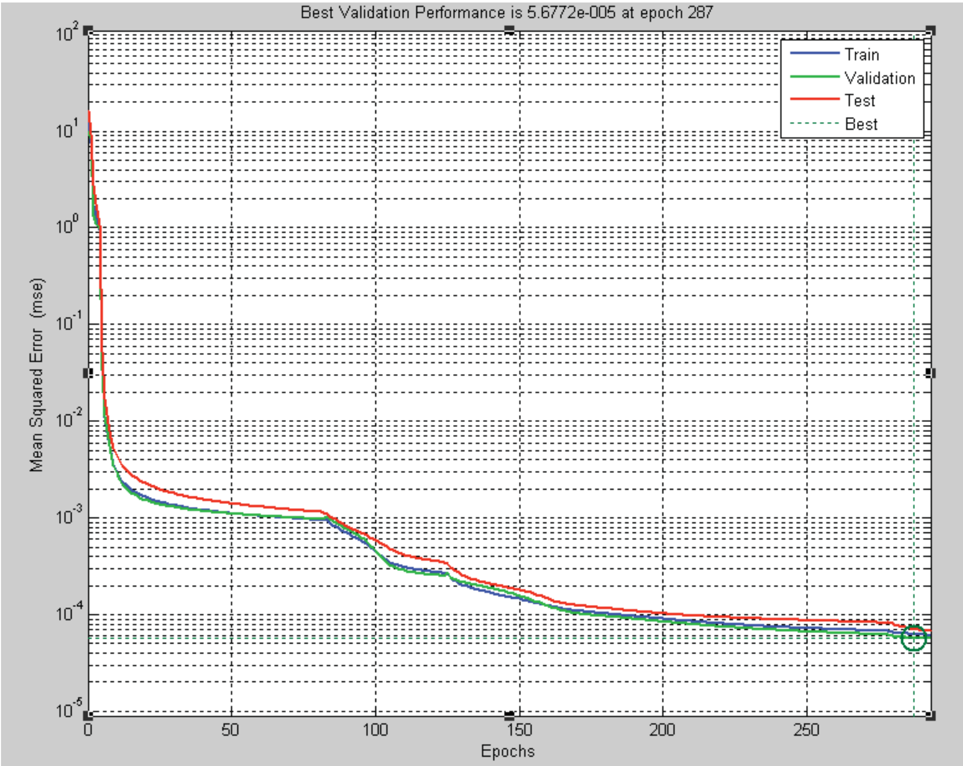


Figure 3 shows the training and testing performance.

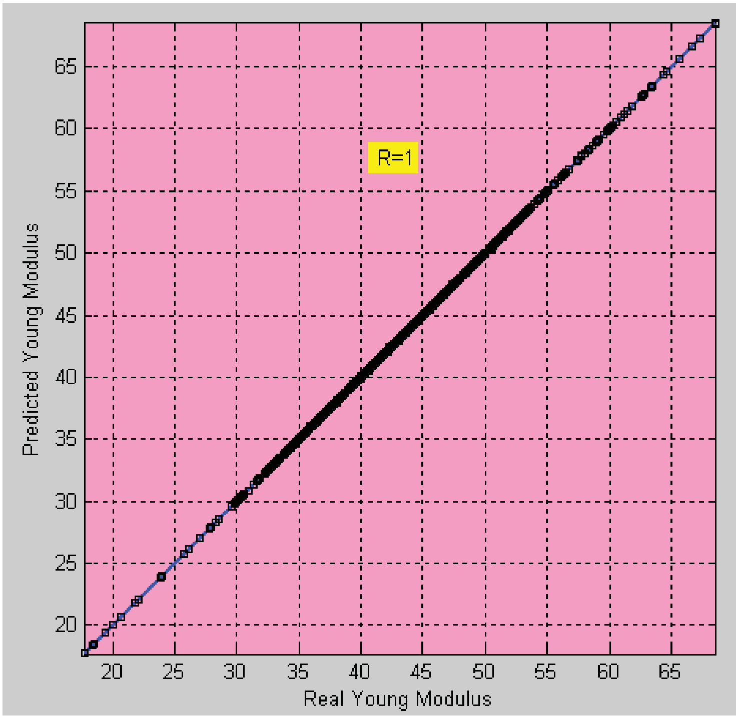


Figure 4 shows the relationship between real and predicted Young's Modulus.

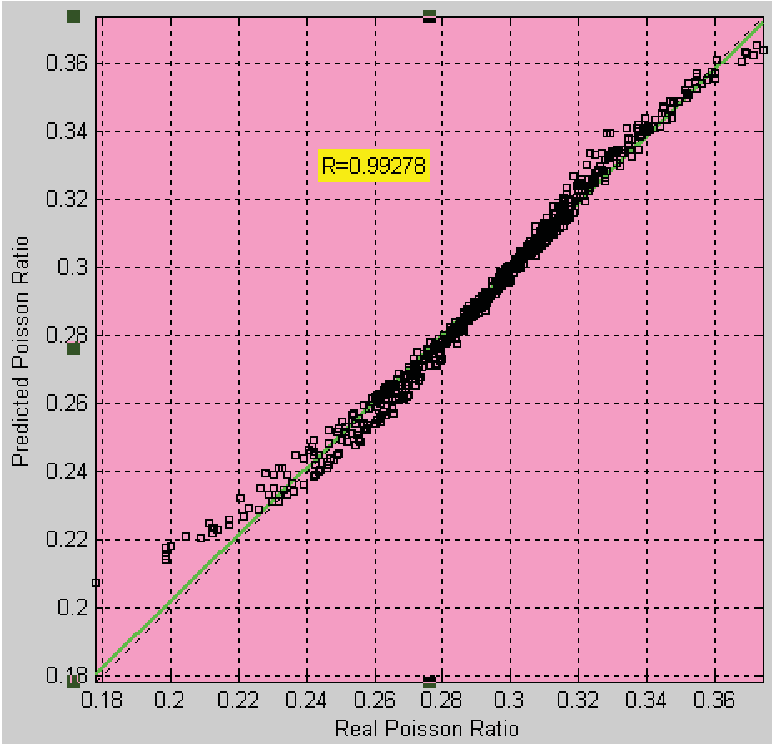


Figure 5 shows the relationship between real and predicted Poisson's Ratio.

The performance of the model as carried out by the test data set shows better prediction of Young's modulus and Poisson's ratio. It was shown that using this method, engineers can easily predict geomechanical rock properties with accuracies similar to real drilling core measurements (static module) where rock samples are not available.

Nomenclature

ARE = average relative error

$$ARE = \sum((Ap - Ameas)/Ameas)/N$$

AARE= average absolute relative error

$$AARE = \sum(ABS|(Ap - Ameas)/Ameas|)/N$$

Ap= Predicted

Ameas= Measured

σ_{min} = the minimum horizontal stress (in-situ stress)

υ = Poissons' ratio

σ_{ob} = overburden stress

α = Biot's constant

σ_p = reservoir pore pressure

σ_{ext} = tectonic stress

E = Young's modulus.Pa

σ_{z1} = Stress at axial point z1, Pa

σ_{z2} = Stress at axial point z2, Pa

ξ_{z1} = Strain at axial point z1, Pa

ξ_{z2} = Strain at axial point z2, Pa

ξ_{x1} = Strain at lateral point x1, Pa

ξ_{x2} = Strain at lateral point x2, Pa

References

1.-Clark, P. E. et al., "Design of a Large Vertical Prop Transport model," Paper SPE 6814 presented at the 1977 SPE Annual Conference and Exhibition, Denver, Oct. 9-12.

2- Gidley et al.: Recent Advances in Hydraulic Fracturing, SPE Monograph 12, Richardson, Texas, (1989).

3.-Vispyf.Bharucha.: Rheological Study of Hydroxypropyl Guar (HPG) Slurries.Msc.Thesis, Norman, University of Oklahoma, 2004

4-Musaed N. J. Al-Awad: "Simple Correlation to Evaluate Mohr-Coulomb Failure Criterion Using Uniaxial Compressive Strength.", Journal of King Saud University, Engineering Sciences, Vol. 14, No. 1, pp. 137-145, 2001.

5-Musaed N. J. Al-Awad: "Rock Mechanics Applications in Petroleum Engineering Practices." Oil and Gas European Magazine (International Edition of ERDOIL ERDGAS KOHIL), Germany, Vol. 4, No.1, pp. 18-20, December 1998.

6-Alkhathami, Mohammad " Investigation of Proppant Transport in Hydraulic Fractures "Submitted in Partial Fulfillment of the Requirement of the Degree of Bachelor of Science in Petroleum Engineering ,King Saud University, January , 2007

7- Salz, L.B.: "Relationship Between Fracture Propagation Pressure and Pore Pressure", paper SPE 6870 presented at the 1977 SPE Annual Technical Conference and Exhibition, Denver, Oct. 7-12.

8- Veatch, R. W. Jr. and Moschchovidis, Z. A.: "An Overview of Recent Advances in Hydraulic Fracturing Technology", paper SPE 14085 presented at the 1986 International Meeting on petroleum Engineering, Beijing, March 17-20.

9- Howard, G. C., and Fast, C. R.: "Hydraulic Fracturing," Monograph Volume 2 of SPE, 1970.

10- Musaed N.J. Al-Awad and Talal Y. AlAhaidib: "Estimating the Amount of free Sand in the Yielded Zone around Vertical and Horizontal Oil Wells.", SPE-SA0526, The 2005 SPE Technical Symposium of Saudi Arabia Section held in Dhahran, Saudi Arabia, 14-16 May 2005.

11-Hae-sik Jeong, Seong-seung Kang, Yuzo Obara: "Influence of surrounding environments and strain rates on the strength of rocks subjected to uniaxial compression.", International Journal of Rock Mechanics & Mining Sciences 44 (2007) 321–331.

12-Jaeger J.C. and Cook N.G.W. : "Fundamentals of rock mechanics." 3rd edition, Chapman and Hall, London, 593p., 1979.

13- Abass, H.H., "Sand Control: Sand Characterization, Failure Mechanisms, and Completion Methods", (2002), Society of Petroleum Engineers Inc. (SPE 77686).

14-J. Arukhe, "Horizontal Screen Failures in Unconsolidated, High-Permeability Sandstone Reservoirs: Reversing the Trend", (2005), Society of Petroleum Engineers Inc. (SPE 97299).

15- Abass, H.H. et al: "Oriented Perforation - A Rock Mechanics View," paper SPE 28555 (1994).

16- Abass, H.H. and Neda, J.:"Rock Mechanics in Wellbore Construction" Chapter 6 of "Petroleum well Construction", edited by Economidies, M.J., Watters, L.T., and Dunn-Norman, S.., John Wiley & Sons, Ltd, 1998.

17-Haykin S. 1999. Neural Networks: A Comprehensive Foundation. Prentice-Hall, Inc.

18-Rumelhart, D. E., Hinton, G. E., and Williams, R. J., 1986. Learning internal representations by error propagation. In Parallel distributed processing; foundations, ed. Rumelhart, D. E., and McClelland, J. L., 318-362. Cambridge: MIT Press.

19-Rogers, S.J., Chen, H.C., Kopaska-Merkel, D.C. and Fang J.H. 1995. Predicting permeability from porosity using artificial neural networks. AAPG Bulletin 79: 1786-1797

20-Bowles, 1996. J.E. Bowles , Foundation Analysis and Design. , McGraw-Hill, New York (1996).

21- Saemi, M., Ahmadi, M., Integration of genetic algorithm and a coactive neuro-fuzzy inference system for permeability prediction from well logs data, Porous Med (2008) 71:273–288.

Wellsite Geochemical Analysis Speeds Decision-Making with Near-Real-Time Data

By Weatherford International Ltd Staff

Cutting days and weeks from a critical well process can be challenging at best. However, for unconventional shales, new capabilities that move geochemical analysis out of the lab and onto the wellsite are achieving that remarkable feat.

Understanding organic richness is fundamental to producing unconventional shales. That knowledge has required laboratory analysis of drilling cuttings in a process that typically takes the better part of a month – not slow, but nowhere near real time.

Now the critical analysis is taking place at the wellsite in about half an hour. Integrated with surface logging gas analysis, the two evaluation capabilities provide high-quality, near-real-time data on shale oil and gas content. The game-changing reduction in delivery time of data promises to affect everything from steering the bit to planning for rigs and leases.

"Our surface logging systems (SLS) and laboratories both have specialized formation evaluation services that, when combined at the wellsite, can provide a comprehensive organic and inorganic geochemistry service unique in the industry," comments Bruce Henderson, Weatherford International Ltd's Vice President, Surface Logging Systems. "By taking advantage of the SLS, wellsite-located-logging unit, this service can be provided during the well construction phase of the well, while drilling is occurring – providing a high value service with many benefits to the client."

Speed Has Its Value

"Data has a half life," explains Henderson Watkins, General Manager of Global Operations for Weatherford Laboratories. "It's more valuable to someone in an hour than a week or a month. Because timely data evaluation is so critical to our client's business, we naturally look for ways to improve that process."

"This integration and evaluation of laboratory geochemical testing and advanced surface logging gas chromatography datasets leads to better decisions," says Watkins. "And the unique ability to provide this data quickly at the wellsite enables new options for decision makers that can have huge results at several different levels."

Perhaps the most significant result of wellsite geochemistry is the ability to provide information for optimally steering the bit. Faster turnaround also optimizes rig time and enables important completion decisions to be made with the rig on location. In addition, it affects decisions regarding coring, surface and wireline logging, stimulation, and other wellsite activities.

Taking Lab Experience to the Field

Wellsite geochemical analysis is part of a comprehensive capability the company has for laboratory and field analysis of cores, fluids and gas, and surface logging advanced gas chromatography and measurements, as well as data management. It depends on two key technologies – the Source Rock Analyzer (SRA) and the GC TRACER™ surface logging device.

SRA technology acquires geochemical data to determine organic richness, thermal maturity and in-situ hydrocarbon saturations in about half an hour from sample acquisition. In unconventional reservoirs, the information can aid in the delineation of pay zones and be used to design horizontal completion and stimulation programs.

The pyrolysis technique that it applies – a process that heats rock samples to release gas and liquids for analysis

Source Rock Analyzer. The SRA uses the pyrolysis of geologic samples (conventional and side-wall cores, cuttings and outcrops) to identify and characterize hydrocarbon zones with a high degree of precision.

– has previously been limited to a lab environment. To transfer the technology to the field, several constraints were overcome. The lab units were too large for field use and the electronics were not rugged enough for the harsh conditions. In addition, mobile pyrolysis instrumentation also needed an expanded linear range to handle the wide variety of sample types and fluid concentrations that could be experienced in the field.

The gas chromatograph tool also provides a unique capability. It applies a patented membrane technology to provide consistent, detailed hydrocarbon gas analysis at the wellsite. The tool is a major innovation in surface logging technology. Compared to conventional technologies such as gas agitator traps, it provides more precise data up to four times faster and can identify fluid type and organic rich "sweet spots" as the well is being drilled.

Marketplace Repercussions

The ability to acquire near real-time total organic content (TOC) and pyrolysis measurements is useful for operators. In addition to geosteering, rig optimization and other operational capabilities, the rapid availability of reservoir data also has strategic benefits. Planning for the next well can begin earlier, providing an advantage in leasing acreage or reserving a rig.

Because the operator doesn't have to wait weeks for information, they can be much more aggressive in these efforts. This additional piece of information can further enhance management decision-making.

This integration of field and laboratory services is broadening the scope of the company's decision-enhancing data and interpretive services. While laboratory services will continue to play a significant role, extending key capabilities to the field is central to speeding up the decision-making process. Additional enhancements are nearing completion.

"We will soon be bringing other analytical instruments to the wellsite, further enhancing our position in the geochemistry field, thereby creating something totally new to the industry," says Henderson. "That will enable us to further provide real-time information about mineralogy and rock brittleness as an aide to positioning laterals and picking frac points."

The cross discipline nature of the technologies opens

Advanced surface gas detector extracts formation gas samples from drilling fluid.

greater opportunities to package a broader scope of complementary services, from mud logging to logging-while-drilling (LWD) to wireline. Operators can now benefit from this fully integrated formation evaluation competency.

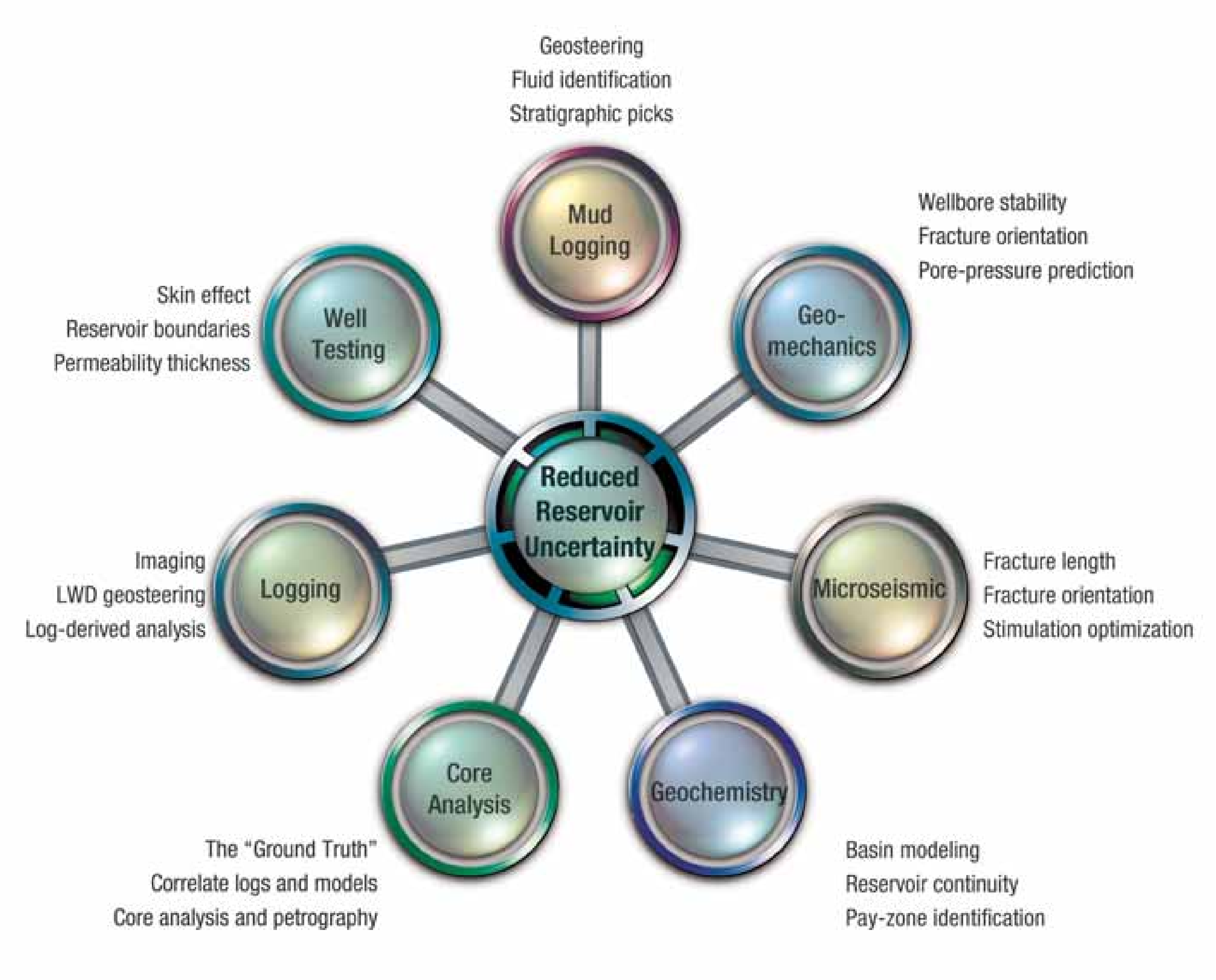
DJ Basin Proving Ground

The company's new analytical tools for wellsite geochemical evaluation were recently demonstrated in the Wattenberg field, part of the Denver-Julesburg (DJ) basin east of Denver, Colorado, and are the subject of a paper to be delivered at the 2010 AAPG Conference in New Orleans, Louisiana. The SRA mobile pyrolysis instrument and gas chromatograph tool were combined to evalate potential productivity of the field's Cretaceous shales during the drilling of a tight gas well.

"The application was important because it showed this integrated wellsite services approach was capable of providing the client with real-time information," says Tim Ruble, Senior Geochemist at Weatherford Laboratories. "The well was analyzed more as a science well than to determine any set completion objectives," he says. "The client wanted to know that they could actually get quality information on which they could base decisions."

"The well ultimately did produce shows of condensates and oil," says Ruble. "Those shows matched analysis predictions for both wellbore location and production characteristics."

The field in the DJ basin was a good study because of its thick shale section. As a result, the analysis was able to



Integrating data sets with interpretive expertise through a hub-and-spoke communications infrastructure enables lower risk and more timely decisions by reducing the impact of geological uncertainty.

collect a continuous series of data, rather than a much shorter section targeting a specific objective.

"We got a beautiful data set," says Ruble. "I'm really excited to go to AAPG to present this – it's rare you find a geologic situation where you can get data like this through a continuous sequence."

Marcellus Evaluation

An analysis conducted in Pennsylvania's Marcellus shale compared wellsite geochemical data with triple combo log data. The results were very positive. The analysis performed on historical well data showed that the two datasets could be used to draw important interpretation conclusions.

"The gas-in-place numbers we calculated from our basic geochemical analysis and the numbers from the log analysis matched up very close with each other over the entire interval," says Ruble. "As a matter of fact, astonishingly close."

That encouraging success has led to an enthusiastic effort to integrate more geochemical and log-analysis data through combined projects. We are working closely with the logging people to expand these capabilities and determine what other opportunities might exist," says Ruble.

Advancing Shale Development

Early applications of wellsite geochemical analysis have shown that the technology can provide high quality in-formation about potential productive shales. The near-real-time availability of that data provides decision-making insights that have far-reaching implications for successful shale development – a significant step in providing a truly integrated formation evaluation capability.

The Use of the Industry's First 3-D Mechanical Caliper Image While Drilling Leads to Optimized Rotary-Steerable Assemblies

By Junichi Sugiura, SPE, and Steve Jones, SPE, PathFinder Energy Services

Abstract

It has been widely recognized that poor hole quality causes tight hole, hole packing off, high torque/drag, stick-slip, degraded logging-while-drilling (LWD) and wireline log quality, unpredictable directional performance, and consequently problematic casing runs. Conventionally, borehole quality is monitored with LWD standoff caliper logs and caliper images. In wireline application, multi-arm mechanical calipers are used to create such logs. Until today, it is believed that the use of such equipment is the only way to detect 3-D borehole problems, such as borehole oscillation.

This paper presents the industry's first 2-D and 3-D mechanical caliper image while drilling, reaming and back-reaming with RSS. The near-bit mechanical caliper integrated into the specific RSS takes measurements 4 ft from the bit in push-the-bit configuration and 7 ft from the bit in point-the-bit configuration. This pad-contact mechanical caliper provides both real-time and memory-based caliper images.

The advantage of this new type of near-bit caliper measurement is that the sensor measures borehole geometry right at the bit as compared to 50-100 feet behind the bit with conventional LWD sensors. Borehole washout, for example, does not necessarily occur at the bit, but could be caused by string stabilizers far away from the bit. The ability to detect borehole washout in real-time helps the operator to take immediate corrective action to maintain borehole integrity while drilling since near-bit washout often affects the steerability of RSS.

In this paper, 2-D and 3-D near-bit caliper logs are extensively evaluated from different RSS assemblies and bits. The data was gathered through controlled non-commercial field tests, as well as commercial runs. Frequency analysis using the discrete Fourier transform is also applied to the depth-based caliper images to identify the BHA and borehole oscillation issues.

The effect of bit selection, stabilizer size/profile/geometry, and spacing on borehole quality has been analyzed using the 2-D and 3-D near-bit caliper logs. As a result, the use of this new sensor information helped to improve the RSS assembly performance and resulted in optimized BHAs in both push- and point-the-bit configurations for superior steerability, stability and borehole quality.

Introduction

In 1951, MacDonald and Lubinski explained the precise definition of so-called "crooked hole" or "spiral hole" and provided a formula for the maximum drift size (MaxDrift) with a given bit (BitDiam) and collar (CollarDiam) combination.[4,5] According to Lubinski, the maximum drift that can occur in a "crooked hole" is defined as:

$$MaxDrift = \frac{BitDiam + CollarDiam}{2}$$

Since Lubinski's study (57 years ago), significant progress has been made in understanding the oscillating or cyclic nature of persistent borehole problems. Mechanical calipers obtained from wireline logs and acoustic standoff calipers from LWD logs have accelerated this advancement in understanding the borehole oscillation problems. Pastusek et al. described the three most common forms of borehole oscillations: a) rippling, b) spiraling, and c) hour-glassing. 3-D graphical represen-

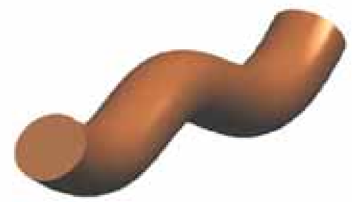


Figure 1a: Rippling

Figure 1b: Spiraling

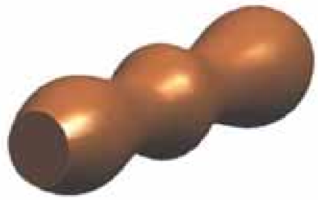


Figure 1c: Hour-glassing

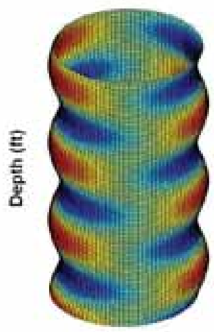


Figure 2a: Rippling

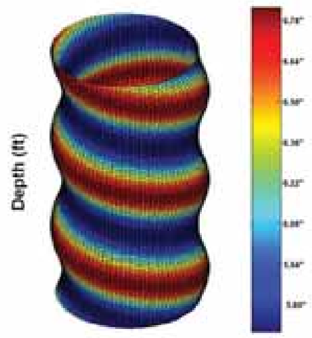


Figure 2b: Spiraling

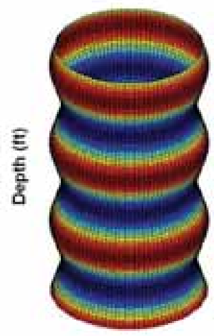


Figure 2c: Hour-glassing

Figure 3a: Rippling

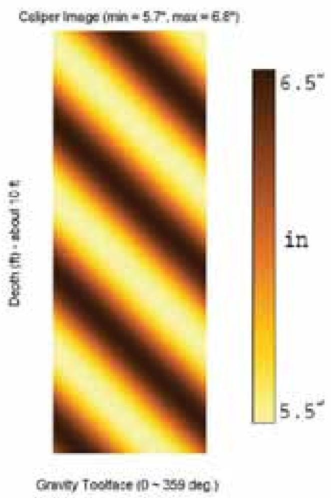


Figure 3b: Spiraling

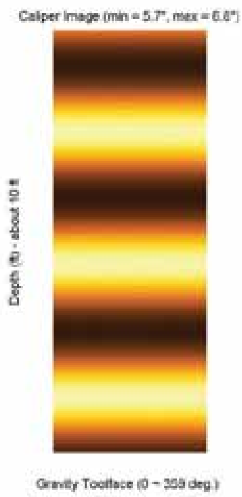


Figure 3c: Hour-glassing

tation of the three most common oscillation forms is shown in Figures 1a, 1b, and 1c (Excerpted from SPE 84448).

In this paper, slightly different 2-D and 3-D caliper images/representations are used. To clarify our visualization convention, the corresponding 2-D and 3-D caliper images are shown in Figures 2a, 2b, and 2c and Figures 3a, 3b, and 3c.

In Figures 2a, 2b, and 2c, the furthest and nearest points from the tool center are shown in red and blue respectively. In the figures, the right side of the image is highside of borehole (gravity toolface = 0°) and the left side of the image is lowside of borehole (gravity toolface = 180°).

In Figures 3a, 3b, and 3c, the furthest and nearest points from the tool center are shown in dark brown and light

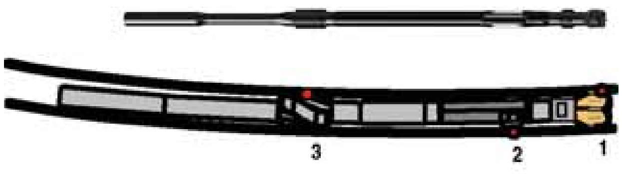


Figure 4a: RSS in push-the-bit configuration

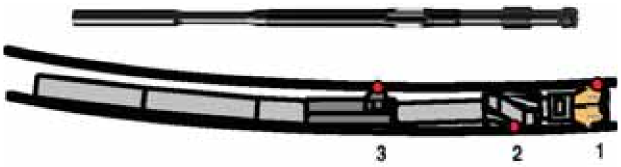


Figure 4b: RSS in point-the-bit configuration

yellow respectively. In the 2-D image (Figure 3), the right and left edges of the image correspond to high-side (gravity toolface = 0°) of borehole and the image center corresponds lowside (gravity toolface = 180°) of borehole. The following section introduces the RSS that was used to create the mechanical caliper image while drilling.

Rotary Steerable System

RSS technology has advanced remarkably since its infancy, and as such, the drive principles and mechanisms used in commercial RSS have become significantly diverse. Common terminology among Drilling Engineers refers to these systems as either push-the-bit or point-the-bit. The particular RSS discussed in this paper has evolved to be run in both push-the-bit and point-the-bit configurations. Figures 4a and 4b shows the 3-point geometry contact points for each configuration.

In push-the-bit mode (4a), the steering unit is used to push the bit sideways in the desired steering direction. In point-the-bit mode (4b), a near-bit stabilizer is used to act as a fulcrum point and tilts the bit in the desired direction. There are advantages to both systems depending upon the application. Typically the system runs in push-the-bit mode if excessive hole wash-out is expected, or if higher doglegs are required. The following section provides a short description of the RSS used in the test program.

Non-Rotating Steering Unit

The steering unit of this specific RSS uses three hydraulically actuated pads for directional control. These pads also act as an anti-rotation device, to hold the steering unit stationary while drilling ahead. All three pads make full contact with the formation, and steering is accomplished by offsetting the steering unit in the desired direction. In point-the-bit mode, a full-gauge near-bit stabilizer is used as the fulcrum point, allowing the bit to tilt in the steered direction. In addition to providing a pivoting point, the use of a full-gauge near-bit stabilizer can dampen lateral shocks that may originate from the drill bit.

The RSS controls the DLS by varying the amount of offset that the steering unit creates from the center-line of the hole. The system is designed to maintain Target Toolface and Target Offset in a closed-loop fashion. As the steering unit turns slowly while drilling, the pads are constantly adjusted to achieve the target settings. This continuous adjustment to maintain orientation of the steering unit allows the system to drill a constant curve.

The pads on the steering unit apply a constant force to the borehole wall, essentially acting as a hydraulically dampened bushing to stabilize the lower part of the BHA. Variations in hole diameter are accounted for by floating one of the pads, which means that a designated pad's hydraulic circuit is open to high pressure fluid from the hydraulic reservoir. This "floating pad" concept allows the tool to maintain sufficient grip, to act as an anti-rotation device, and to provide vibration dampening to the lower part of the BHA for enhanced stability.

Mechanical Caliper While Drilling

Since the steering unit uses pad extension to measure offset from the center of the hole, the same measurements are used to calculate accurate hole caliper. Each extension of three pads is measured with an accurate position sensor. This information is incorporated with the gravity toolface of each pad and is fed to the proprietary image generation algorithm.

Near-bit mechanical caliper measurements and images while drilling are very useful in determining borehole conditions. It is well known that reduced steering performance and DLS capability are a function of over-gauge hole and poor borehole quality. For instance, maintaining wellbore quality such as hole gauge is crucial to the steering performance of some RSS. Knowing the actual hole diameter close to the bit not only helps the system maintain accurate constant curvature drilling, but also informs the operator in real time that hole enlargement may be present. If borehole oscillations are

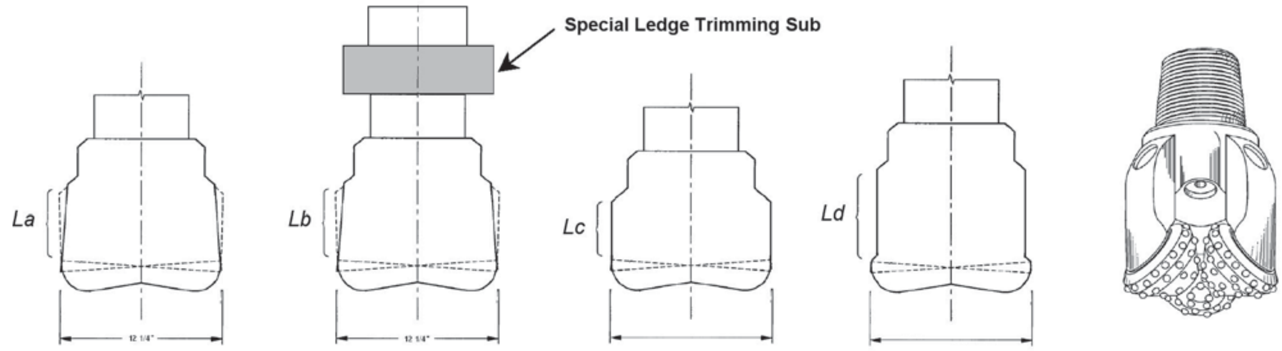


Figure 5a: Bit A **Figure 5b:** Bit B **Figure 5c:** Bit C **Figure 5d:** Bit D **Figure 5e:** Bit E

also found to be hindering directional performance, the appropriate remedial measures can be taken in a timely manner.

On this particular RSS, each adjustable steering pad can travel up to approximately 1 inch from fully collapsed to fully extended, making the system more predictable in washed-out holes. Other systems having less pad travel could have a problem in washed-out hole due to anti-rotation device slippage.

Test Facilities

Confidential drilling test facilities were selected for evaluating different bit and RSS configurations in both push-the-bit and point-the-bit modes. The systematic bit and RSS testing was conducted in two different facilities: 1) the GTI Catoosa Test Facility near Tulsa, Oklahoma and 2) the Rocky Mountain Oilfield Test Center (RMOTC) near Casper, Wyoming.

Both facilities provided adequate geological variations and rig/pump capabilities for RSS tests in 8 ½″ and 12 ¼″ hole sizes. With no directional constraints at either of the facilities, they both offered a perfect test ground for controlled testing.

Test Results

Since 2004, the point-the-bit and push-the-bit RSS have been extensively tested with various hole sizes (8 ½″, 8 ¾″, 12 ¼″, and 16 ½″) and different bit gauge profiles. For optimal comparison test results, it was necessary to drill the same formation at exactly the same TVD, angle and direction. This was done by setting cement plugs when required to sidetrack the well and twin the original test hole as closely as possible.

The main objective of the controlled tests was to establish the maximum dogleg using various RSS configurations and at the same time evaluate the system for steerability, stability and borehole quality. Due to the confidential nature of these test results, the exact contact-point spacings and outer diameter (OD) of stabilizers and steering units will not be published.

Bit Testing – Push-the-Bit

The 8″ push-the-bit RSS had been optimized for spacing touch points during initial development. However, in the previous tests, a special ledge trimmer (a separate undergauge sub) was run with the active gauge, tapered gauge, and partial-ring gauge bits to increase lateral stability. In this experiment, this ledge trimmer sub was removed. The standard commercial spacings were used to conduct the bit tests to optimize for maximum borehole quality and hence superior steerability and stability. For all tests, similar surface parameters were used (WOB = 10 ~ 20 klbs, rotary speed = 110 ~ 120 RPM, and flow rate = 600 GPM). The RSS was set for 91% offset setting.

Drill Bits Tested

During the initial development of the 8″ push-the-bit RSS, it was discovered that the combination of an active gauge bit and a ledge trimming sub produced the highest DLS (5.8°/100ft) while providing excellent bit, BHA stability and high-quality borehole. Basically, the active gauge bit provides maximum side cutting for demanding DLS (or hard formation) applications and the ledge trimming sub keeps the hole on gauge to allow the assembly to pass through. Since the ledge trimmer helps create a smoother wellbore, improved hole quality enables the steering unit to position more accurately and hence results in higher DLS.

In this set of experiments, various polycrystalline diamond compact (PDC) bit gauge profiles were tested to evaluate hole quality and hence the knock-on effect of improved steerability and stability in a hard carbonate rock application (limestone). Five different bit types (one with a ledge trimming sub) were tested. They are named as Bits A, B, C, D, and E as shown below. Bits A, B, C, and D are all PDC bits. A roller-cone bit (Bit E) was also tested as a comparison. Figures 5a, 5b, 5c, 5d, and 5e show bit profiles and gauge features schematically.

Bit A: Tapered Gauge Bit
Bit B: Tapered Gauge Bit with a ledge trimming sub
Bit C: Passive Gauge, short, parallel gauge, full-gauge
Bit D: Passive Gauge, long , undercut
Bit E: Roller-cone Bit

The exact tapered angles, gauge lengths and gauge diameters remain confidential; however, relative gauge lengths among PDC bits are published. The gauge lengths of Bits A, B, C, and D are expressed as La, Lb, Lc, and Ld respectively. The following relationship is known.

$$La = Lb \quad \text{and} \quad Lc < La \leq Lb < Ld$$

Bits A and B are identical (the same tapered angle and gauge length), and the only difference is the use of a special ledge trimming (undergauge) sub, which added an extra distance (about 1 foot) between a bit and the pads. This extra 1-foot spacing is expected to reduce the DLS capability in this test. In a prior bit testing, an integrated ledge trimming sub was used, and it did not add any length to the spacing. Bit C has the shortest passive gauge length, whereas Bit D has the longest passive gauge length.

Steerability:
One aspect of the important bit design quality is the steerability, which affects the amount of response to a bit side force. Push-the-bit RSS require a high-side cutting ability of a bit for high DLS applications. In general, an optimized bit gauge design, matched with a given RSS, provides effective side cutting and precise toolface control to achieve required DLS for a given interval and given formation. Table 1 shows the maximum DLS achieved and the resultant toolface obtained from measurement-while-drilling (MWD) static survey. Since the testing was conducted in both sandstone and limestone, the following results also show the corresponding lithology.

MWD surveys were taken as often as possible to capture any short interval tortuosity of the borehole. However, the survey data was influenced by statistical errors due to short course length. In the above table, resultant toolface deviation is shown to illustrate RSS toolface accuracy (i.e. how well the RSS was able to maintain toolface control with a given bit).

Both Bits A and B drilled in sandstone. Bit A produced higher DLS without a special undergauge sub, but resultant toolface was erratic. Bit B with the undergauge sub did not produce high DLS due to an added spacing, but the toolface control was best. In this test, a tapered gauge bit with an undergauge sub (Bit B) produced 4.0 DLS, whereas in the prior test, the same combination produced 5.4 DLS. This reduction in DLS (≈1.4 °/100ft) is caused by the extra 1-foot spacing between a bit and the pads. Bit B drilled in both sandstone and limestone sections and exhibited the same steerability with good toolface control. In limestone, Bit B produced the highest ROP, whereas Bit E (a roller-cone bit) generated the lowest ROP. Bit C (a short passive gauge bit) produced the highest DLS while exhibiting relatively high ROP.

Stability:
Another aspect that influences wellbore quality is the ability to stabilize the lower part of BHA since lateral and torsional vibration will contribute to wellbore enlargement. Bit gauge design and cone profile come into play in this aspect. BHA instability can have a significant negative effect on the RSS directional performance and reliability. While testing, concurrent near-bit caliper and vibration data enabled the engineers and researchers to make comparative analysis of bit/BHA stability and

Table 1: 12 ¼" drill bit comparison from the Catoosa test

12 ¼" Bit Type	Bit A	Bit B	Bit B	Bit C	Bit D	Bit E
Lithology	Sandstone	Sandstone	Limestone	Limestone	Limestone	Limestone
DLS (°/100ft)	4.8	4.0	4.0	5.8	4.6	4.0
Build Rate (°/100ft)	4.7	3.9	3.9	5.7	4.5	3.6
ROP (ft/hr)	62	55	40	33	28	11
Resultant Toolface (°)	±10	±2	±3	±4	±5	±10

Table 2: 12 ¼" drill bit comparison from the Catoosa test

12 ¼" Bit Type	Bit A	Bit B	Bit B	Bit C	Bit D	Bit E
Lithology	Sandstone	Sandstone	Limestone	Limestone	Limestone	Limestone
Lateral Vibration Level	1.2	1	3.5	4	4.5	6
Axial Vibration Level	1	1	2	3	3	6
Torsional Vibration Level	0	0	0	1	1	0

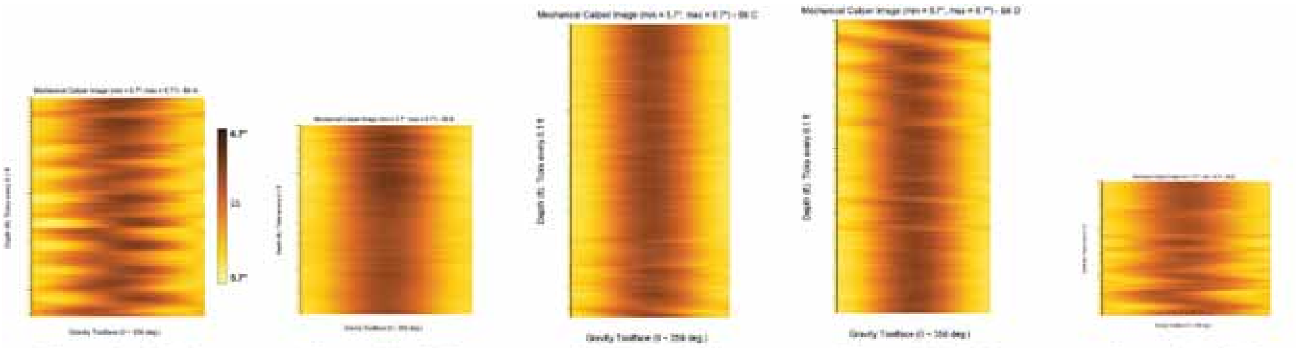


Figure 6a: Bit A **Figure 6b:** Bit B **Figure 6c:** Bit C **Figure 6d:** Bit D **Figure 6e:** Bit E

borehole quality among different bit/BHA configurations. Table 2 shows the near-bit vibration severities observed with different bits. Vibration severities are computed with a proprietary process and treated as unit-less numbers.

Both bits A and B drilled in sandstone with very low vibrations. Once the RS BHA entered into limestone, lateral and axial vibration levels were both increased with all the bit types. In limestone, the tapered gauge bit with ledge trimmer exhibited lowest vibration levels, whereas the roller-cone bit produced highest lateral and axial vibration levels.

Borehole Quality:

In RS drilling, gauge hole and good borehole quality are very important in enabling the system to deliver consistent directional response. High-quality borehole provides the system with smooth torque and rotation response. Erratic torque and RPM fluctuations are often caused by erratic hole diameters, ledges and borehole oscillation problems, which may lead to tool operation problems, inconsistent steering response, and, in the worst case, the premature failure of bit, RSS and BHA components.

To aid comparative analysis of borehole quality, the newly developed 2-D and 3-D mechanical caliper images while drilling are used. These multi-dimensional images make it easier to understand borehole shapes more intuitively. Visualization is a powerful tool to evaluate bit and RSS performance in a qualitative manner. Figures 6a, 6b, 6c, 6d, and 6e show the 2-D images of the borehole drilled with bits A, B, C, D, and E respectively. Since a push-the-bit RSS was used to test maximum build-up capability, the caliper distance at the lowside of the borehole is generally higher than the distance at the highside. This tendency can be observed in the darker colors at the center of the image.

As can been seen from the above images, the borehole created with Bit B shown in Figure 6b has the smoothest color and texture distribution, which signifies a high-quality borehole. Figures 6a and 6e shows a strong borehole oscillation problem as zig-zag stripes can be seen in the images. The boreholes generated with a tapered gauge bit and roller-cone bit exhibited worst borehole quality as these bits have no or little lateral stability. Figures 7a, 7b, 7c, 7d, and 7e show the 3-D images of the borehole. In the following 3-D images, borehole oscillation problems, ledges, erratic borehole surface can

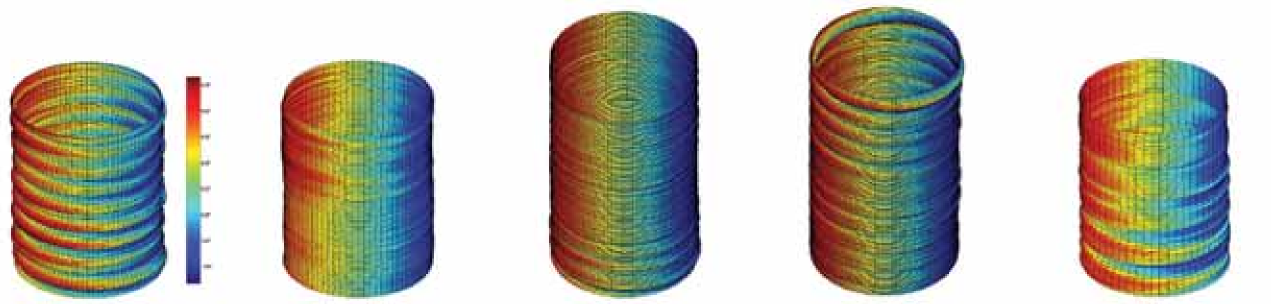


Figure 7a: Bit A **Figure 7b:** Bit B **Figure 7c:** Bit C **Figure 7d:** Bit D **Figure 7e:** Bit E

Figure 8a: Bit A **Figure 8b:** Bit B **Figure 8c:** Bit C **Figure 8d:** Bit D **Figure 8e:** Bit E

be visually confirmed. In the figures, the right side of the image is highside of borehole (toolface = 0°) and the left side of the image is lowside of borehole (toolface = 180°). The push-the-bit RSS positioned close to the highside of borehole in a build-up application and this fact can be confirmed from the image as the highside is colored in blue.

It is very obvious that Bit B generated the highest borehole quality as shown in Figure 7b. Generally, this kind of smooth borehole is referred to as a "Gun Barrel" hole. This high-quality borehole was observed with Bit B in both sandstone and limestone sections while the RSS was set to produce maximum build-up rate. In Figure 7a (with Bit A), a persistent borehole oscillation problem can be observed. In Figure 7c, the drill bit C started creating ledges and forming a borehole oscillation problem near the end of the run. These ledges were developed to be full hole spiral as can be observed in the beginning of the drill bit run with Bit D in Figure 7d. In this run with Bit D, the borehole oscillation was self-healed for an unknown reason. Bits B, C, D, and E were all tested in Mississippi Limestone, and there were no formation changes between the runs. A roller-cone bit (Bit E) also created borehole oscillation problems as shown in Figure 7e. Overall, the roller-cone bit generated the lowest build-up rate, poor toolface control, high lateral and axial vibration, and low-quality borehole.

Frequency Analysis on Caliper Image:

One of the most popular mathematical tools used in science and engineering for frequency analysis is Fourier transform. The discrete Fourier transform was applied to the above images to extract cyclic nature of borehole problems. The following frequency spectrum images, shown in Figures 8a, 8b, 8c, 8d, and 8e, represent a magnitude of the cyclic signals in the depth-domain data. A strong frequency response is shown as a black (or dark brown) vertical line. The position of the line in x-axis represents the frequency of borehole oscillation. The closer the frequency response is to the left edge of the image, the lower the frequency is. Y-axis represents the measured depth.

Obvious borehole oscillation response can be observed in Figures 8a, 8c, 8d, and 8e. Figure 8a (with Bit A) shows the strongest oscillation evidence as the darkest line appears in the image. From this image, it can be

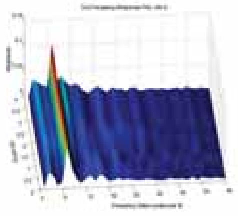


Figure 9a: Bit A

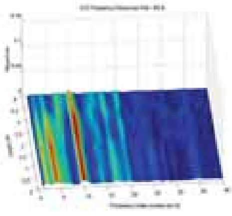


Figure 9b: Bit B

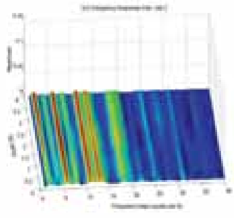


Figure 9c: Bit C

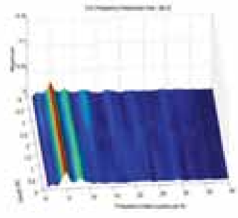


Figure 9d: Bit D

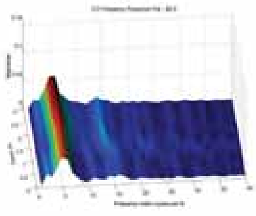


Figure 9e: Bit E

said that the oscillation response was slowly amplified as the hole was drilled ahead. In Figure 8e (with a roller-cone bit), a medium-to-high borehole oscillation can be observed as a brown line. The positions of the lines are always at the same place among four images because the oscillation period corresponds to the distance between the bit and pads (the first stabilization point behind the bit).

In Figure 8c, toward the end of the run, a brown line started to appear, which is the early sign of borehole oscillation problem. This tendency was carried out to the next run with Bit D since borehole ledges and spiral had already been created. In Figure 8d, at the beginning of the run, borehole spiral existed, but this bit quickly dumped the oscillation as the run progressed. By the time 20 ~ 30 ft was drilled, borehole spiral became a series of cyclic ledges and continued to diminish.

In the Figure 8b (a tapered gauge bit with a special undergauge sub), borehole oscillation problem cannot be observed, at least, at the same frequency (a distance period between a bit and pads) as the others exhibited. Instead, a slight line (frequency response) can be observed at a higher frequency (a shorter period). This line is almost unnoticeable as the oscillation magnitude is very low. This frequency response approximately corresponds to the distance between a bit and the undergauge sub. In all cases, the fundamental frequency response (other than DC component) exists at the distance period between a bit and the first stabilization (or contact) point.

The above 2-D frequency spectrum plots are perfectly suitable for LWD logs. However, it requires trained eyes to recognize frequency responses with very small magnitude. Figures 9a, 9b, 9c, 9d, and 9e show 3-D plots of the frequency spectrum. Frequency, measured depth, and magnitude are shown in x, y, and z axes respectively.

The height of the plot in z-axis shows the magnitude of frequency response. Local minima and maxima are colored in blue and red respectively. This coloring scheme makes it easier to see very small frequency responses in a spectrum image. For example, a higher frequency peak in Figure 9b (with Bit B) can be observed clearly, and this peak is the dominant frequency response in this run. Figure 9c highlights the fact that there were several small frequency responses in the testing with Bit C. This multiple frequency responses are caused by the gauge profile of the short passive gauge bit (full gauge). Figure 9e shows that the borehole oscillation frequency response of the roller-cone bit is much broader than that of the tapered gauge. This response could be due to more axial vibration/motions generated by the roller-cone bit as well as broader side contact points of the bit.

Overall Analysis

The following section summarizes the findings from the systematic drill-bit testing. For overall analysis, MWD survey and surface parametric data are used in combination with downhole memory data recorded by the RSS. Analysis results are categorized by the bit types.

Bit A (Tapered gauge bit)
In a prior testing, a combination of a taper gauge bit and ledge trimming sub produced 5.4 DLS while, without the special sub, the same bit produced 4.8 DLS. The reduced DLS is caused by borehole oscillation problems and erratic toolface control. Since the bit has a tapered gauge and allows the RSS freedom to side cut easier, the lateral stability is less than that of a bit with long passive gauge. This side cutting capably with little lateral stabilization was suspected to cause the bit to ledge and the initiation of borehole oscillation problems. The ta-

per angle and the gauge length should be carefully designed to match the RSS steering mechanism and geometry. Ideally, the gauge diameter should be sufficiently large at the back end of the passive gauge to prevent ledging while steering. Though this bit did not generate a lot of vibration in sandstone, the bit created borehole oscillation problems that limited the DLS capability and precision of steering. In the frequency spectrum of the borehole profile, a strong and sharp oscillation response at the period between the bit and pads is observed.

Bit B (Tapered gauge bit with ledge trimming sub)
The ledge trimming sub added an extra 1-foot of spacing to the distance between the bit and pads. This BHA produced 4.0 DLS which is the lowest DLS of all, and the same as the roller-cone bit produced. This bit drilled 715ft total and maximum build-up tests were carried out in both sandstone and limestone sections. The maximum DLS and toolface controllability in both formations are very similar. In the Mississippi Limestone, lateral and axial vibration severities are both substantially increased. This assembly produced the best borehole quality with least vibration. Since the 2-D and 3-D borehole images created in sandstone and limestone look extremely similar (high-quality borehole), the images from limestone is omitted in the previous pages. The spectrum images of the borehole caliper reveal that there are very small frequency responses. Two of them are noticeable. The period of the highest frequency response corresponds to the distance between the bit and the ledge trimming sub. The period of the second highest frequency response appears at the distance between the bit and pads. Since the bit-to-pad distance is longer in this assembly, the corresponding frequency is lower than these of other assemblies. Overall, this bit and ledge trimming sub combination produced limited maximum DLS while providing high BHA stability, high ROP, and high-quality borehole. For high DLS applications, the ledge trimming sub should be integrated to the lower part of the BHA to reduce the distance between the bit and pads.

Bit C (Passive gauge bit with short, parallel, full-gauge)
This bit has a short passive, parallel, full-gauge profile. Since the passive gauge length is short, the bit generated the highest DLS among all the bits tested, with reasonable toolface control and good ROP. At the same time, the short passive gauge bit provided medium lateral stability. Lateral vibration was higher than that of the tapered gauge with the ledge trimming sub, but lower than these of Bits D and E. The resultant borehole quality is a medium-to-high level; however, toward the end of the run, the borehole started oscillating. Excluding the borehole oscillation part, this bit produced the highest build rate with reasonable lateral vibration levels and borehole quality. The frequency spectrum of the caliper shows that the peak of the frequency response is at the distance between the bit and pads, but other peaks are located at higher frequencies. These higher frequency components are induced by the different contact points created by the parallel passive gauge bit. Performance improvement could be expected by extending the passive gauge length with reduced gauge diameter at the end.

Bit D (Passive gauge bit with long, undercut)
This bit has a long passive gauge, but the gauge diameter is undercut. At the beginning of the run, this bit followed previously spiraled hole and this tendency was carried out for a while. In the 2-D and 3-D borehole images, it can be observed that at least small oscillation was always present, but as the run progressed, the oscillation started fading. This bit exhibited the second lowest DLS among all the bits and resultant toolface was not very accurate. The low DLS is thought to be caused by the lack of side-cutting structure on the bit. The corresponding frequency analysis revealed that a low-to-medium borehole oscillation was present at the period between the bit and pads. The bit has a long passive gauge, but it is undergauge. The lateral stability of this bit is considered to be medium to high since it dumped the borehole oscillation problem. The gauge length and undercut depth should be carefully reviewed to mach with the particular RSS.

Bit E (Roller-cone bit)
Overall, the roller-cone bit generated the lowest build-up rate, poor toolface control, high lateral and axial vibration, and low-quality borehole. Unlike a passive gauge PDC bit, the roller-cone bit tested does not have gauge structures to enhance lateral stability and resulted in borehole oscillation problem. Borehole oscillation period of the bit matched with the spacing between the bit and pads. However, the frequency response in the spectrum is much broader than that of the taper gauge bit due to the axial vibrations and motions created by the bit and the contact point interaction between its cones and the formation. In a previous test, it is confirmed that a combination of a roller-cone bit and a separate ledge trimmer sub exhibited good steerability with high-quality borehole. To be compatible with the push-the-bit RSS, the bit must be run with a special ledge trimming sub. Alternatively, a roller-cone bit with lug pads can be used to increase lateral stability of the bit as reported by Stroud et al.

Future Work

The lessons learned from the advanced caliper imaging analysis will be implemented to design laterally stable RS BHA that provides highest DLS and borehole quality. The different types of commercial and prototype RS bits will be tested without a special ledge trimming sub to analyze what gauge design criteria are required to eliminate borehole oscillation problems for a given formation strength and directional objectives.

Conclusions

The selection of optimum drill-bit gauge geometry for a push-the-bit RSS in a hard carbonate rock application requires expert knowledge on RSS driving mechanisms/geometry and drill-bit gauge features/geometry supported by an extensive systematic testing of drill bits and BHAs. In-depth analysis of the data from advanced LWD is necessary to fine-tune the drill bit and RS BHA in a given formation, interval, and directional requirement. Achieving high dogleg from an RSS is relatively easy, but balancing stability and drillability requires more involved testing and analysis. The results from several years of systematic bit/RSS testing has delivered the following conclusions:

• 2-D and 3-D mechanical caliper images while drilling help recognize borehole oscillation problems

• Frequency analysis of the borehole caliper revealed that there are multiple borehole oscillation frequencies that correspond to the distance periods between a bit and other side contact points in the RS BHA.

• A peak frequency response of borehole caliper resides generally at the period between the bit and the first stabilization point.

• Aggressive side cutting without proper lateral gauge stabilization induces borehole oscillation problems.

• Tapered gauge bit and a roller-cone bit produced borehole oscillation problems without ledge trimming sub.

• The ledge trimming sub maintains the hole on gauge by trimming ledges and hence improves borehole quality even with a full active gauge bit.

• The ledge trimmer prevents a local high dogleg from happening and hence suppresses borehole oscillation problems.

• Maximum DLS itself must not be used to quantify the performance of bit and/or RS BHA. Stability and borehole quality are equally important in system-level RS drilling performance.

• Increasing spacing between the steering unit and bit in the push-the-bit mode led to a drastic decrease in build rate.

• A roller-cone bit generated highest axial vibration due to its rock breaking (removal) mechanism.

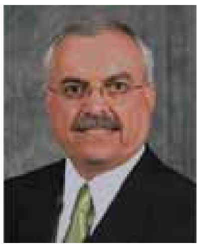
• A roller-cone bit has broaden peak frequency responses in depth-based caliper data.

• A short, passive, parallel gauge bit produces multiple frequency responses due to its touch points against the borehole.

Acknowledgments

We would like to thank PathFinder Energy Services for their willingness to provide the data obtained with the 12 ¼″-hole-size PathMaker® RSS. We are grateful to PathFinder Energy Services for permitting the publication of this work.

MESSAGE FROM THE 2010 SPE PRESIDENT



On behalf of the Society of Petroleum Engineers, I am pleased to welcome you to the first Annual Technical Symposium and Exhibition, organized by SPE and the Dhaharan Geological Society to be held in Al-Khobar, Saudi Arabia.

We offer our congratulations to the Technical Committee for developing this outstanding programme on "The Race to Ultimate Recovery: People, Technology and Beyond." This event offers technical presentations, panel sessions and poster sessions. The symposium covers geology and geophysics, as well as wide range of exploration and production topics.

We are all keenly aware of the serious technical challenges our industry faces in finding and producing the oil and natural gas resources needed to meet growing world demand for energy. The Saudi Arabia Section's Annual Technical Symposium and Exhibition has a 25-year history of bringing together regional and international industry professionals to exchange knowledge and to promote the latest innovations and technologies. We know that both talented people and advanced technology will be required. This region holds a huge supply of the world's resources. Sharing our collective experiences and knowledge will be the key to unlocking its full potential.

I hope you will enjoy the conference, find it stimulating and informative, and take away knowledge that will help you improve performance.

Dr. Behrooz Fattahi

2010 SPE President

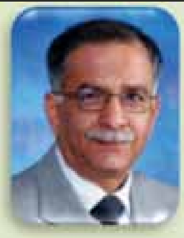
"This region holds a huge supply of the world's resources. Sharing our collective experiences and knowledge will be the key to unlocking its full potential."

Saudi Arabia Section

Opening Ceremony Keynote Speakers

Dr. Behrooz Fattahi
President
Society of Petroleum Engineers

Dr. Jeroen Regtien
Vice President, Hydrocarbon Recovery Technologies
Shell International Exploration and Production B.V.



Mr. Abdulla Al-Naim
Vice President, Exploration
Saudi Aramco

Opening Ceremony Keynote Speakers

Dr. Behrooz Fattahi
President
Society of Petroleum Engineers

Dr. Jeroen Regtien
Vice President, Hydrocarbon Recovery Technologies
Shell International Exploration and Production B.V.

Mr. Abdulla Al-Naim
Vice President, Exploration
Saudi Aramco

Panel Discussion	
"Toward 70% Recovery Factor: Multiple Disciplines, Different Methods, One Goal"	
Moderator:	**Dr. Muhammad M. Al-Saggaf** *Chief Petroleum Engineer, Petroleum Engineering* *Saudi Aramco*
Panelists:	**Mr. Carlos Morales-Gil** *Director General, E&P* *PEMEX* **Dr. Ganesh Thakur** *Vice President , Global Advisor & Chevron Fellow* *Chevron Energy Technology Company* **Mr. Hussain M. Al-Otaibi,** *Manager, Exploration Technical Services Department* *Saudi Aramco* **Mr. Omer Gurpinar** *Technical Director, Enhanced Oil Recovery* *Schlumberger* **Dr. S. M. Farouq Ali** *President* *Heavy Oil Recovery* **Mr. Waleed A Mulhim** *Manager, Southern Area Reservoir Management Department* *Saudi Aramco*

Keynote Luncheon Speakers
Mr. Belgacem Chariag *President, Eastern Hemisphere Operations* *Baker Hughes*
Mr. Ashok Belani *Chief Technology Officer* *Schlumberger*
Mr. Mark Richard *Vice President, Business Development and Marketing* *Halliburton*

Invited Speaker
Mr. Zuhair A. Al-Hussain *Vice President, Drilling and Workover* *Saudi Aramco*
Dr. Mohammed Badri *Managing Director, Schlumberger Dhahran Carbonate Research* *Schlumberger*
Mr. Grant Smith *Vice President, Marketing* *Baker Hughes*
Mr. Ahmed Sabry *Manager, Consulting Services* *Schlumberger*
Mr. Ali M. Al-Shahri *Manager, Northern Area Reservoir Management Department* *Saudi Aramco*
Dr. Bradford Macurda *President The Energists Houston, Texas*
Mr. Saad A. Turaiki *Vice President, Southern Area Oil Operations* *Saudi Aramco*
Mr. Saleh Al-Maghloth *Manager, Exploration Operations* *Saudi Aramco*
Mr. Arend Snaas *Manager, Middle East Business Unit* *Weatherford International*
Mr. Omer Gurpinar *Technical Director, Enhanced Oil Recovery* *Schlumberger*

Saturday, April 4

Pre-Event Technical Courses

Location (Saudi Aramco, Dhahran)	**Saturday, April 4** **Technical Courses** **08:00 – 11:30** *Registration will be closed by March 31st,2010, please contact Fahad.Intisar@bakerhughes.com*
E2-CR, 2nd Floor, Engineering Building	**Intelligent Field Infrastructure and System Data Flow Overview** *Soliman Almadi, Saudi Aramco* Provide detailed technical overview of the different I-Field Infrastructure components including PDHMS, Smart Completion, Multiphase Flow Meter, surface instrumentations and the supervisor Control Data Acquisition Application system and capabilities. This session will also include an overview for data flow journey from the sensor to the engineer's desktop. Study case scenarios will be used to demonstrate best practices as well as optimal deployment strategies.
T-5A, 5th Floor, Tower Building	**Tight Gas Rock Mechanics and Development** *Prof. Mark Zhobach* The course will be aimed at giving an overview of the basics of rock mechanics and development options for tight gas reservoirs.
E3-CR, 3rd Floor, Engineering Building	**Engineering a CT UBD Well Sweep Assessment in Aquifer Supported** *Baker Hughes* The course will be aimed at giving an overview of the planning process to engineer a re-entry on an oil or gas well using CT UBD technology. Brownfield development continues to grow to fuel the thirst for energy in recent years. CT UBD technology has been successfully used around the world to enhance production, minimize reservoir damage and increase reserves from depleting reservoirs. This course helps understand the planning process for engineering a CT UBD candidate well.

T-4A, 4th Floor, Tower Building	**Deep Gas Drilling Optimization** *Baker Hughes* The course will be aimed at giving an overview of the planning process and technologies available to optimize drilling on deep gas wells.

Pre-Event Field Trips

Location	**Saturday, April 4** **Field Trips** **08:00 – 15:30** *Registration will be closed by March 31st,2010, please contact mohammad.otaibi.24@aramco.com*
Half Moon Bay Dunes, Sabkhas, and Salt	**Unayzah 'A' Sandstone Reservoir Outcrop** *Christian J. Heine, Saudi Aramco* Analogs both modern & outcrop provide a 3-D visualization of what a producing reservoir looks like. We will compare the modern dune fields south of Dhahran to the Unayzah 'A' aeolian reservoir. Typically we evaluate a reservoir based on an eight-inch wellbore (core & logs). The field trip is designed to 'fill-in' the gaps between wells spaced 1-3 kilometer apart… The 'Sabkah & Salt' part of the trip will complete the modern desert environment.
Saudi Aramco, Dhahran	**The Geology of the Dammam Dome** **Dr. Wyn Hughes, Saudi Aramco** The Dammam Dome is the location of the origin of oil in Saudi Arabia, and the discovery well Dammam 7 will be observed and a brief history provided. The field trip will then progress through the three Tertiary formations that are exposed within the Saudi Aramco camp. The Rus Formation, of Lower Eocene age, consists of mostly dolomitic carbonates with interbedded marls and mudstones of shallow marine origin. The overlying Dammam Formation, of Middle Eocene age, had a variable depositional environment and the Midra, Saila, Alveolina and Khobar members will be examined. The pre-Neogene unconformity is well exposed, and the overlying shallow marine carbonates of the Dam Formation, of Middle Miocene age, will be examined.

Monday, April 5

Technical Sessions

Session 1	**Monday, April 5** **Hall-A** **Drilling Operations** **08:00 – 09:45** ***Session Chairpersons:*** *Fahad Mulaik, Saudi Aramco* *Dr. Qamar Sharif, Saudi Aramco*	
08:00 – 08:30	*Invited Speaker:* **Mr. Zuhair A. Al-Hussain** *Vice President, Drilling and Workover* *Saudi Aramco*	
08:30 – 08:55	SPE-KSA-0008	**Prediction of Hole Cleaning Efficiency Using a Simple, User Friendly and Better Performing Simulation Model** *Abdullah M. Al Qahtani and Md. Amanullah, Saudi Aramco*
08:55 – 09:20	129600	**Managed Pressure Drilling in Rub Al-Khali Empty Desert: Case Study Sarah-Qasim Formations** *Joseph Ekpe, Andrey Kompantsev, Jamal Al Thuwaini, Emad Mohammad, Yuri Belousov, Ayman Ashoor, and Rauf Khanlerov, Luksar*
09:20 – 09:45	SPE-KSA-0011	**Effect on Borehole Inclination, Annular Clearance, on the Hole Cleaning Efficiency for Water Based Drilling Muds** *Mohamed N. Noui-Mehidi and Dr. Mohamed Amanullah, Saudi Aramco*

Session 2	Monday, April 5 **Advances and Challenges in Reservoir Characterization** *Session Chairpersons:* *Mohammed Al-Khalifa, Saudi Aramco* *Khalid Al-Ramadhan, KFUPM*		Hall-B 08:00 – 09:45
08:00 – 08:30	*Invited Speaker:* **Dr. Mohammed Badri** *Managing Director, Schlumberger Dhahran Carbonate Research* *Schlumberger*		
08:30 – 08:55	SPE-KSA-0056	**Geomechanical Engineering of Tight Gas Sand Developments** *Michael A. Addis and N. Yassir, GeoMechanics International (GMI)*	
08:55 – 09:20	SPE-KSA-0046	**Variable Rate UBD Production Data Facilitates Reservoir Characterization** *Sunil Lakshminarayanan, Weatherford International ; George Stewart, Said Boutalbi and Jaime Villatoro*	
09:20 – 09:45	SPE-KSA-0146	**Recent Applications and Learning's from Advanced Geosteering Techniques in Ultra-Thin Carbonate Reservoirs** *Ali Al-Julaih, Maher Al-Mashadi, Troy Thompson, and Majid Al-Otaibi, Saudi Aramco*	

09:45-10:00 Coffee Break

Session 3	Monday, April 5 **Completions Technology** *Session Chairpersons:* *Jimmy Phillips, Saudi Aramco* *Mohammed Abduldayem, Weatherford International*		Hall-A 10:00 – 11:15
10:00 – 10:25	SPE-KSA-0049	**A Decision Support System for Cost-effective Assessment of Sand Production Risk and Selection of Completion Type** *Md. Khalil Rahman, Abbas Khaksar, and Toby Kayes, Baker Hughes*	
10:25 – 10:50	125788	**Openhole ICD completion with fracture isolation in a horizontal slimhole well - Case study** *Peter E Smith, Dustin Young and Mohammed Al-Muraidhef, Halliburton; Mohammed Zaki bin Awang, Saudi Aramco*	
10:50 – 11:15	SPE-KSA-0139	**A Novel Command Activated Sandface Valve to Improve Wellbore Productivity** *Malcolm Adam, Omega Completion Technology Ltd*	

Session 4	Monday, April 5 **Reservoir Simulation** *Session Chairpersons:* *Dr. Hamoud A. Al-Anazi, Saudi Aramco* *Leopoldo Sierra, Halliburton*		Hall-B 10:00 – 14:45
10:00 – 10:25	SPE-KSA-0045	**Analysis of Capillary Pressure and Relative Permeability Effects on the Productivity of Naturally-Fractured Gas Condensate Reservoirs** *Bander Nasser Al Ghamdi and Luis Felipe Ayala H.m, SaudiAramco*	
10:25 – 10:50	SPE-KSA-0058	**Optimization of Well Design and Location in a Real Field Using Continuous Genetic Algorithm** *Ahmed Y. Bukhamsin, Khalid Aziz, and Mohammed Farsh, Saudi Aramco*	
10:50 – 11:15	SPE-KSA-0026	**Field Application of Composite Reservoir Model on Non-Unit Mobility Flow,** *Abdallah Al Gahtani and Anes Usman, KFUPM*	

11:15 – 12:30	*Keynote Luncheon Speaker:* **Belgacem Chariag** *President, Eastern Hemisphere Operations* *Baker Hughes*	**Main Hall**
	Lunch & Prayer Break	
	Luncheon Generously Sponsored By **Baker Hughes**	

Session 5	Monday, April 5 **Production Operations** *Session Chairpersons:* *Dr. Abdullah Al-Qahtani, Saudi Aramco* *Fahad Intisar, Baker Hughes*	Hall-A 12:30 – 14:15
12:30 – 13:00	*Invited Speaker:* **Mr. Grant Smith** *Vice President, Marketing* *Baker Hughes*	
13:00 – 13:25	SPE-KSA-0083	**Remote Operations at Shell - a case history from the giant NAM Groningen Gas Field in the Netherlands** *Douwes A. Brugt, Shell*
13:25 – 13:50	SPE-KSA-0102	**Rigless Water Shut Off** *Alaa S. Shawly, Saudi Aramco*
13:50 – 14:15	SPE-KSA-0037	**Effective Crude Oil Export Sales Management Towards A Robust Economy** *Mohammed H. Siddiqui, and Franklin Rodricks, Saudi Aramco*

Session 6	Monday, April 5 **Geophysical Analysis: Methods And Technology** *Session Chairpersons:* *Youness El Ouair, Saudi Aramco* *Husam Al-Mustafa, Saudi Aramco*	Hall-B 12:30 – 14:15
12:30 – 13:00	*Invited Speaker:* **Mr. Ahmed Sabry** *Manager, Consulting Services* *Schlumberger*	
13:00 – 13:25	SPE-KSA-0038	**Three-Dimensional Inversion of Borehole Gravity Measurements for Reservoir Fluid Monitoring** *Khaled Hadj Assi and Jean-Marc Donadille, Schlumberger*
13:25 – 13:50	SPE-KSA-0108	**Unlocking The Low Frequencies For Ultimate Relative Impedance Inversion** *Iian T. Martin and Steven Helmore, Baker Hughes*
13:50 – 14:15	SPE-KSA-0164	**Near-surface modeling using surface-waves** *Khaled A. Al Dulaijan, Saudi Aramco*

14:15-14:40 Coffee Break

Session 7	Monday, April 5 **Stimulation Technology** *Session Chairpersons:* *J. Ricardo Solares, Saudi Aramco* *Nihat Gurmen, Schlumberger*	Hall-A 14:40 – 15:55
14:40 – 15:05	SPE-KSA-0035	**Merging Tapered in Coiled Tubing (CT) and Well Tractor Technologies to Effectively Stimulate Extended Reach Open Hole Horizontal Wells** *Mubarak A. Al Dhufairi and Saleh AlGhamdi, Saudi Aramco; E. Krueger and B. Moore, WWT; Samer Alsarakbi, Adrian Weiss, and Vidal Noya, SPE, Schlumberger*
15:05 – 15:30	SPE-KSA-0131	**Associative Polymer Usage as Stimulation Diversion System for Multilayered Reservoirs: Case Study of its Effectiveness for Stimulating Tight Layers in the Khuff** *Abdulaziz K. AL Harbi, Saudi Aramco*
15:30 – 15:55	SPE-KSA-0151	**Evaluation of Triazine-Based H_2S Scavengers for Stimulation Treatments** *Khalid Y. Al Duailej, H. Al-Mutairi, and Adel Y. Al- Humaidan, Saudi Aramco*

Tuesday, April 6

Session 8	Tuesday, April 6 **Reservoir Performance Management** *Session Chairpersons:* *Dr. Ali A. Al-Yousif, Saudi Aramco* *Abdulaziz Al-Amoudi, Shoaibi Group*		Hall-A 08:00 – 09:45
08:00 – 08:30	*Invited Speaker:* **Mr. Ali M. Al-Shahri** *Manager, Northern Area Reservoir Management Department* *Saudi Aramco*		
08:30 – 08:55	SPE-KSA-0095	**Ensemble-Based Methods for Reservoir Life-Cycle Optimization and Well Placement** *Olwijn Leeuwenburgh, Paul Egberts, Oscar Abbink, TNO*	
08:55 – 09:20	SPE-KSA-0158	**A Novel Tight Reservoir Fracture Characterization Approach: Pressure Transient Interpretation of Formation Tester Reservoir Pressure Responses** *Ahmed H. Alhuthali, Danang R. Widjaja, Rodolfo J. Phillips Guerrero, Saudi Aramco*	
09:20 – 09:45	SPE-KSA-00147	**Maximizing Recovery of Attic Oil from Highly-Fractured Crestal Area Using Horizontal Skimmers: A Case Study** *Ali H. Al Julaih, Brett Fischbuch, Nelson Pinero, and Tareq Al-Zahrani, Saudi Aramco*	

Session 9	Tuesday, April 6 **Geology & Geophysics Case Studies** *Session Chairpersons:* *AbdeFattah Bakheit, Saudi Aramco* *Khalid Al-Hamoud, Saudi Aramco*		Hall-B 08:00 – 09:45
08:00 – 08:30	*Invited Speaker:* **Dr. Bradford Macurda** *President The Energists Houston, Texas*		
08:30 – 08:55	125368	**Exploratory Data Analysis in Reservoir Characterization Projects** *Keith R. Holdaway, SAS*	
08:55 – 09:20	SPE-KSA-0059	**Value of 3D Geomechanical Modeling in Field Development - A New Approach Using Geostatistics,** *Marc Holland, Martin Brudy, Satya Perumalla, and Thomas Finkbeine, GeoMechanics International (GMI)*	
09:20 – 09:45	SPE-KSA-0101	**Tectonic Escape (indentation) in Central Saudi Arabia, Possibility and Exploration Potential** *Mesbah H. Khalil, Emad Muzaiyen, Khalid Hmoud and Luay Ismail, Saudi Aramco*	

09:45-10:00 Coffee Break

POSTER SESSION (10:00 - 11:15)

Paper	Hall-A	Paper	Hall-B
124999	**Proactive Optimization of Oil Recovery in Multilateral Wells Using Real Time Production Data** *Zeid M. Al Ghareeb, Roland Horne, Shamsuddin Shenawi, and Bevan Yuen, Saudi Aramco*	SPE-KSA-0006	**Production Optimization of Multi-Lateral Wells Using Passive Inflow Control Devices,** *Sam Simonian, Drew Hembling, Garo Berberian, Adib Al-Mumen and Giovanni Salerno, Flotechltd.*
SPE-KSA-0011	**Effect on Borehole Inclination, Annular Clearance, on the Hole Cleaning Efficiency for Water Based Drilling Muds** *Mohamed N. Noui-Mehidi and Dr. Mohamed Amanullah, Saudi Aramco*	SPE-KSA-0019	**Successful Extended Reach Approach In Production Logging Applications Using The Agitator Tool** *Alaa Kady and Hamzah Al-Khalifah, Saudi Aramco, Todd Green and Tim Ramsey, BJ Services, Monis Pascal, NOV*
SPE-KSA-0022	**Enhanced Coiled Tubing Intervention Practices on Extended-Reach Open-Hole completion in a Field in Saudi** *Waleed K. Ba Wakid, Saudi Aramco*	SPE-KSA-0026	**Field Application of Composite Reservoir Model on Non-Unit Mobility Flow,** *Abdallah Al Gahtani and Anes Usman, KFUPM*

SPE-KSA-0043	**Automate the Process of Managing Well Logs Data,** *Turki A. Al Ghamdi, Saudi Aramco*	SPE-KSA-0065	**Dielectric Response of Carbonate Core Plugs-Influence of Heterogeneous Rock Properties on Permittivity,** *Tianhua Zhang, Patrice Ligneul, Benjamin Nicot, Fabrice Pairoys, Philip Singer, and Mahmood Akbar, Schlumberger*
SPE-KSA-0102	**Rigless Water Shut Off** *Alaa S. Shawly, Saudi Aramco*	SPE-KSA-0128	**Successful Exploitation of Khuff-B Deep Gas Condensate Reservoir through Optimized Developmental Strategy** *Rhaim Zillur, Hamoud Al-Anazi, and Mustafa Basri, Saudi Aramco*
SPE-KSA-0141	**Innovative Approach to Stimulate Horizontal Gas Well Using DTS Technology Combined with Coiled Tubing in Saudi Arabia** *Francisco Garzon, J. Ricardo Solares, Jose Ricardo Amorocho and Abdulmohsin AL-Mulhim, SPE, Saudi Aramco, Wassim Kharrat, Iyad Hamed-Naji, George Brown and Vidal Noya, SPE, Schlumberger*	SPE-KSA-0145	**Canadian Basin: A Promising Method for Characterizing Fractured Reservoirs in Saudi Arabia** *Mohammed A. Al Duhailan, Saudi Aramco*
SPE-KSA-0148	**Optimizing Horizontal Well Configurations for Effective Oil Drainage from Ultra-Thin, Tight Oil Zones Overlying Thick, Productive Formations under Strong Water** *Brett D Fischbuch, Obai A. Taibah, and Tareq M. Al-Zahrani, Saudi Aramco*		

11:15 — 12:30	*Keynote Luncheon Speaker:* **Ashok Belani** *Chief Technology Officer* *Schlumberger*	**Main Hall**
	Lunch & Prayer Break	
	Luncheon Generously Sponsored By	**Schlumberger**

Panel Discussion

"Toward 70% Recovery Factor: Multiple Disciplines, Different Methods, One Goal"

Moderator:	**Dr. Muhammad M. Al-Saggaf** *Chief Petroleum Engineer, Petroleum Engineering* *Saudi Aramco*
Panelists:	**Mr. Carlos Morales-Gil** *Director General, E&P* *PEMEX* **Dr. Ganesh Thakur** *Vice President , Global Advisor & Chevron Fellow* *Chevron Energy Technology Company* **Mr. Hussain M. Al-Otaibi,** *Manager, Exploration Technical Services Department* *Saudi Aramco* **Mr. Omer Gurpinar** *Technical Director, Enhanced Oil Recovery* *Schlumberger* **Dr. S. M. Farouq Ali** *President* *Heavy Oil Recovery* **Mr. Waleed A Mulhim** *Manager, Southern Area Reservoir Management Department* *Saudi Aramco*

12:30 - 14:15	Panel Discussion	Main Hall

Outline

The industry is aiming to increase recovery factors from 50 to 70%, with a varied array of technology, people, and processes. Currently, it has embarked on a number of technology ventures in an attempt to meet this target throughout collaboration of petro-technical disciplines, from geophysics, geology, petrophysics, drilling, reservoir, production, and completion.

Some examples of the technologies being sought or tested currently include:

Enhanced Oil Recovery agents – CO_2, smart water, chemical EOR
Extreme reservoir contact wells – instrumented and fully automated
Nanotechnology both within the reservoir and in the near wellbore region
Novel deep imaging methods to verify bypassed reserves
I-Field production and reservoir management workflows
Robotic well construction and/or well intervention

These forays into novel technology areas are long term strategy efforts at changing the way petroleum resources are managed, and as such will take time to come to fruition. The implementation phase can be fraught with risks, so the question remains “how does one measure the value of these technological advances?” If it were possible wouldn’t it be nice to “tag” the extra barrel of oil recovered due to the application of some of these technologies?

The panel session is aimed at discussion surrounding the three main areas:

What is being done today in the field in push to improve recovery factor, and what are the key lessons learned.
What key technologies are being developed that can apply to enhancing recovery factor – what are being tested today and what are in the pipeline. What are the challenges in deployment.
How does the industry embrace these key technologies with the risks (and costs) associated with their early adoption. How does one measure the success in meeting the 70% recovery factor goal? Is there technology sufficient to do this to the satisfaction of the key management stakeholders?

Specific Areas of Interest:

1. Current Technologies
   Maximum reservoir contact wells
   Intelligent fields
   Miscible floods
   Reservoir rock typing
   Wettability evaluation in transition zones
   iField and integrated real time field management centers
   Distributed downhole monitoring devices (temperature, pressure etc)
   Enhanced fracture delineation and characterization

2. Technologies Under Development
   Smart water
   Nanotechnologies – nano-bots, or nano-chemistry
   Remote drilling technologies
   Extreme reservoir contact wells
   Distributed downhole monitoring and control systems (flow, phase fractions)
   Cross-well formation and saturation mapping techniques
   Micro-seismics for production
   There are a number of publicized cases which are proving the value of community based research on the back of the “Google” generation – could this be harnessed for the oilfield?

3. Deployment
   Early adoption – cataloguing the risks and defining the value. What are the experiences and learnings?
   Definition of success – how will one measure this success.
   Is there a way to measure the additional recovery in a term acceptable to stakeholders as a KPI? Can this be "tagged" somehow?
   What are the resource and expertise needs to drive this process in achieving the goal?
   What is the role of the iField in this? How best to harness this information superhighway.
   Are there other methods out there that can help?

14:15-14:40 Coffee Break

Session 10	**Tuesday, April 6** **Hall-A** **Production Technology** **14:40 – 15:55** ***Session Chairpersons:*** *Dr. Hamoud A. Al-Anazi, Saudi Aramco* *Jimmy Phillips, Saudi Aramco*	
14:40 – 15:05	124999	**Proactive Optimization of Oil Recovery in Multilateral Wells Using Real Time Production Data** *Zeid M. Al Ghareeb, Roland Horne, Shamsuddin Shenawi, and Bevan Yuen, Saudi Aramco*
15:05 – 15:30	SPE-KSA-0006	**Production Optimization of Multi-Lateral Wells Using Passive Inflow Control Devices,** *Sam Simonian, Drew Hembling, Garo Berberian, Adib Al-Mumen and Giovanni Salerno, Flotechltd*
15:30 – 15:55	132179	**Successful Extended Reach Approach In Production Logging Applications Using The Agitator Tool** *Alaa Kady and Hamzah Al-Khalifah, Saudi Aramco, Todd Green and Tim Ramsey, BJ Services, Monis Pascal, NOV*

Session 11	**Wednesday, April 7** **Hall-A** **Field Development** **08:00 – 09:45** ***Session Chairpersons:*** *Dr. Ali Al-Rabba, Saudi Aramco* *Dr. Saidi Hassani, Saudi Aramco*	
08:00 – 08:30	*Invited Speaker:* **Mr. Saad A. Turaiki** *Vice President, Southern Area Oil Operations* *Saudi Aramco*	
08:30 – 08:55	SPE-KSA-0107	**Optimized Field Development of an Offshore Secondary Carbonate Reservoir in Saudi Arabia** *Dismuke T. Carl and Sarfraz Jokhio, Saudi Aramco*
08:55 – 09:20	SPE-KSA-0148	**Optimizing Horizontal Well Configurations for Effective Oil Drainage from Ultra-Thin, Tight Oil Zones Overlying Thick, Productive Formations under Strong Water** *Brett D Fischbuch, Obai A. Taibah, and Tareq M. Al-Zahrani, Saudi Aramco*
09:20 – 09:45	SPE-KSA-0132	**Best Practices in Khurais Complex Development** *Tony R. Pham, Waleed A. Al-Mulhim, Fahad A. Al-Ajmi, and Mahdi A. Al-Shehab, Saudi Aramco*

Session 12	Wednesday, April 7 Recent Advances In Seismic Data Acquisition And Processing *Session Chairpersons:* *Muneer Al-Sannaa, Saudi Aramco* *Abdullatif Al-Shuhail, KFUPM*	Hall-B 08:00 – 09:45
08:00 – 08:30	*Invited Speaker:* **Mr. Saleh Al-Maghloth** *Manager, Exploration Operations* *Saudi Aramco*	
08:30 – 08:55	SPE-KSA-0062	**Improving Seismic Whitening And Seismic Inversion Workflows Using Frequency Split Structurally Oriented Filters** *Iain Martin and Steve Helmore, Baker RDS*
08:55 – 09:20	SPE-KSA-0145	**Canadian Basin: A Promising Method for Characterizing Fractured Reservoirs in Saudi Arabia** *Mohammed A. Al Duhailan, Saudi Aramco*

09:45-10:00 Coffee Break

Session 13	Tuesday, April 6 Well Testing *Session Chairpersons:* *Abdulaziz Al-Ajaji, Saudi Aramco* *Faisal M. Al-Thawad, Saudi Aramco*	Hall-A 14:40 – 15:55
14:40 – 15:05	SPE-KSA-0136	**A Comparative Study between Empirical Correlations & Mechanistic Models of Vertical Multiphase Flow** *Anas Y. Usman and Abdallah Al-Gathani, KFUPM*
15:05 – 15:30	SPE-KSA-0153	**Pressure Transient Analysis: Characterizing the Reservoir and Much More,** *Badr M. Al Harbi, Saud A. BinAkresh, Abdulaziz A. Al-Ajaji and Edgar J. Pinilla Forero, Saudi Aramco*
15:30 – 15:55	SPE-KSA-0163	**Moving the Immovable: Practical Offshore Appraisal Testing of Sour And Heavy Oil,** *Abdulaziz A. Al-Ajaji, AbdulHakim Al-Nahdi, and Harmohan Gill, Saudi Aramco, Abdur-Rasheed Omidiya, Schlumberger*

Session 14	Wednesday, April 7 Petrophysics and Formation Evaluation *Session Chairpersons:* *Nazih Al-Najjar, Saudi Aramco* *Abdulaziz Al-Duaiji, Saudi Aramco*	Hall-B 10:00 – 14:45
10:00 – 10:25	SPE-KSA-0043	**Automate the Process of Managing Well Logs Data,** *Turki A. Al Ghamdi, Saudi Aramco*
10:25 – 10:50	SPE-KSA-0034	**Leveraging Slim Hole Logging Tools in the Economic Development of the Ghawar Fields** *Izuchukwu I Ariwodo, A. R. AL-Belowi, and R.H. BinNasser, Saudi Aramco; Kuchinski, I. Zainaddin, Weatherford*
10:50 – 11:15	SPE-KSA-0044	**Effect of Temperature and Pressure on Interfacial Tension and Contact Angle of Khuff Gas Reservoir** *Taha M. Okasha and Abdul-Jalil A. Al- Shiwaish, Saudi Aramco*

11:15 – 12:30	*Keynote Luncheon Speaker:* **Mark Richard** *Vice President, Business Development and Marketing* *Halliburton*	**Main Hall**
	Lunch & Prayer Break	**Main Hall**
	Luncheon Generously Sponsored By **Halliburton**	

Session 15	Wednesday, April 7 Workover & Intervention Operations *Session Chairpersons:* Haider Al-Haj, Saudi Aramco Ajmal Wardak, Halliburton	Hall-A 12:30 – 14:15
12:30 – 13:00	*Invited Speaker:* **Mr. Arend Snaas** *Manager, Middle East Business Unit* *Weatherford International*	
13:00 – 13:25	SPE-KSA-0029	**Unique Straddle Design for Placement Inside Damaged Down Hole Safety Valve Nipple Seal Area** *Tor Henning Liland, Are Lund, Therese Johanson, StatoilHydro; Espen Hiorth, BTU; Bjørn Bill, PI Intervention*
13:25 – 13:50	SPE-KSA-0110	**First Worldwide Application of Fiber Optic Enabled Coiled Tubing with Multilateral Tool for Accessing and Stimulating a Trilateral Oil Producer, Saudi Arabia** *Ahmed K. Al Zain, Rifat Said, Salman Gamber, and Saad Al-Driweesh, Saudi Aramco, Khzam Al-Shahrani, and Jan Jacobsen, Schlumberger*
13:50 – 14:15	SPE-KSA-0173	**The Application of Ultrasonic Technologies to Identify Crossflow between Formations, Flow behind Pipe and Casing Leaks** *Mahmood Zakaria and Karim K. Nasr, TecWel; Alejandro Chacon, Guillermo Izquierdo, and Robert Heidorn, Halliburton*

Session 16	Wednesday, April 7 Fluid Flow Mechanisms In Oil & Gas Reservoirs *Session Chairpersons:* Dr. Abdullah Al-Qahtani, Saudi Aramco Wesley Barreto, Schlumberger	Hall-B 12:30 – 14:15
12:30 – 13:00	*Invited Speaker:* **Mr. Omer Gurpinar** *Technical Director, Enhanced Oil Recovery* *Schlumberger*	
13:00 – 13:25	SPE-KSA-0009	**Simulation in Inflow Control Valves Using Lattice Boltzmann Modeling,** *Abdullah M. Al-Qahtani and Mohamed N. Noui-Mehidi, Saudi Aramco*
13:25 – 13:50	SPE-KSA-0033	**Determination of Reservoir Rock Wettability by Thin Layer Wicking Approach,** *Hasan O. Yildiza, F. Bahar Oztoruna, and Ayhan A. Sirkecib, Istanbul University*
13:50 – 14:15	SPE-KSA-0126	**Fluid Flow Mechanisms in a Large Carbonate Reservoir with Fractures** *Tony Pham, Mahdi Al-Shehab, and Ali S. Al-Muallem, Saudi Aramco*

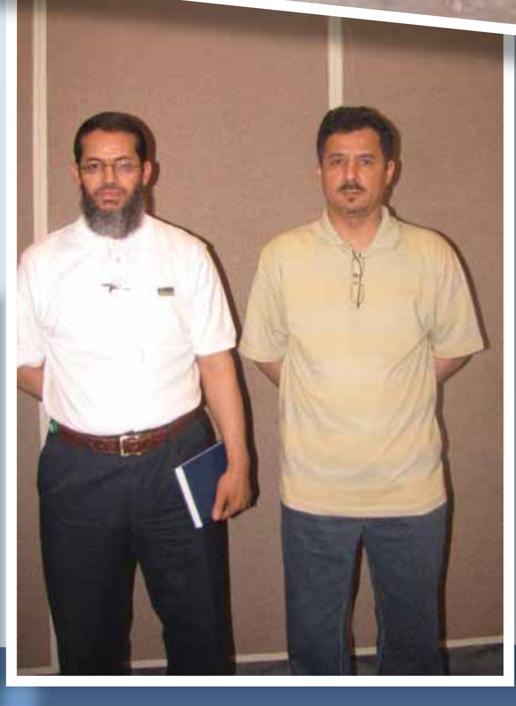
14:15-14:40 Coffee Break

Session 17	Wednesday, April 7 Stimulation Operations *Session Chairpersons:* Dr. Hazim Abass, Saudi Aramco Mohammad Athar Ali, Schlumberger	Hall-A 14:40 – 15:55
14:40 – 15:05	SPE-KSA-0141	**Innovative Approach to Stimulate Horizontal Gas Well Using DTS Technology Combined with Coiled Tubing in Saudi Arabia** *Francisco Garzon, J. Ricardo Solares, Jose Ricardo Amorocho and Abdulmohsin AL-Mulhim, SPE, Saudi Aramco, Wassim Kharrat, Iyad Hamed-Naji, George Brown and Vidal Noya, SPE, Schlumberger*
15:05 – 15:30	SPE-KSA-0125	**Post-Stimulation Results and Analysis of Highly Successful Multi-Stage Acid Fracturing Campaign Performed in Tight Gas Carbonate Formations in Saudi Arabia** *Carlos A. Franco, Ricardo Solares, Nayef Al-Shammari, Moataz AL-HArbi, and Alabbad AL-Eamad, Tomislav, Saudi Aramco*
15:30 – 15:55	SPE-KSA-0138	**Successful Selective Stimulation of Open Hole Dual Lateral Gas Condensate Producers with Coiled Tubing, Hydra Jetting Tool and New Isolation Sleeve In Saudi** *Francisco O. Garzon and Carlos Franco, Saudi Aramco; Guillermo Izquierdo and Leopoldo Sierra, Halliburton*

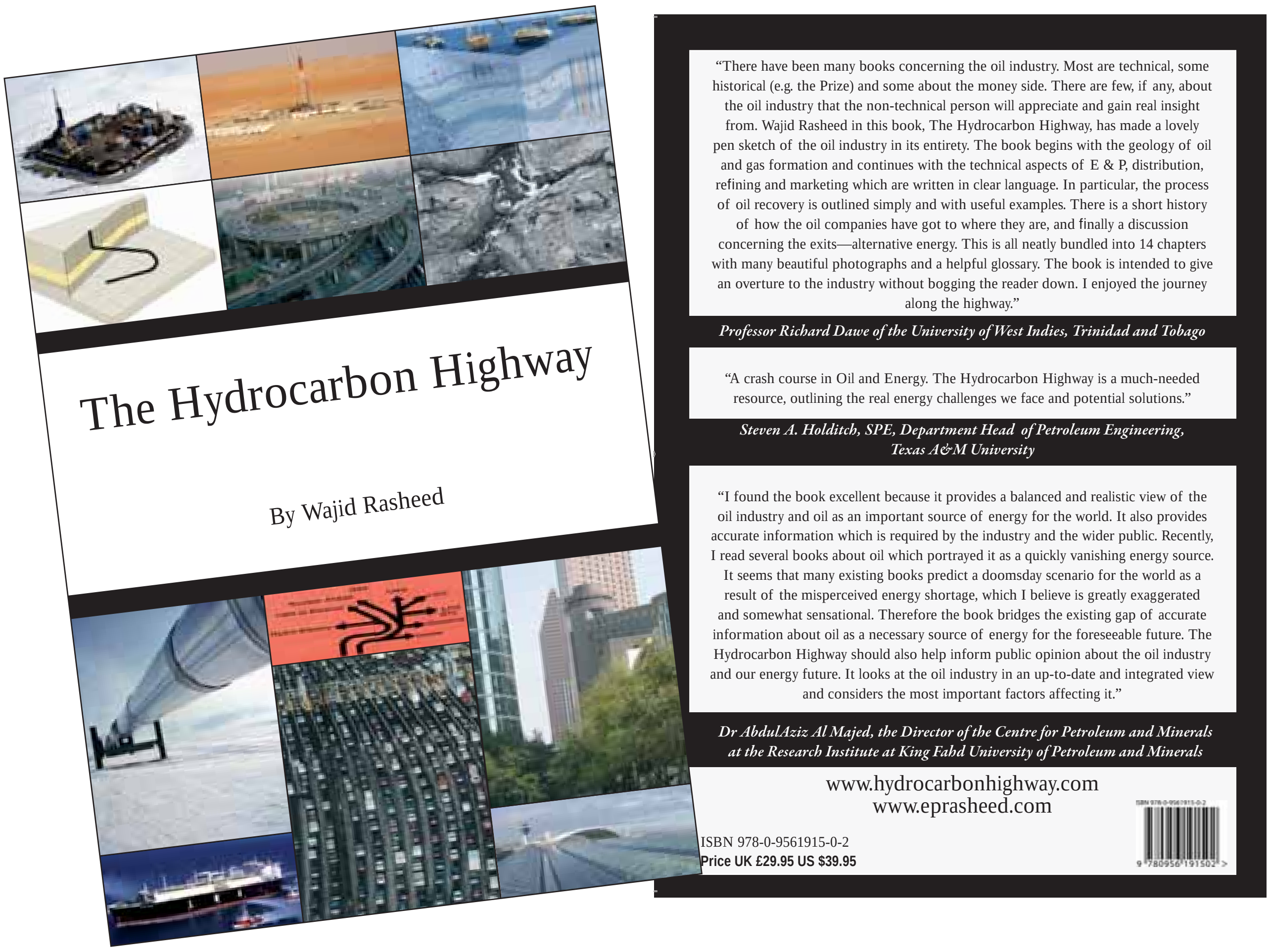
SPE-KSU Students' Chapter

Photos courtesy of KSU PGED.

PGED Khurais Field Trip, 2010



Properties, Players and Processes



Clearly, the most prized possessions in the industry are the leases allowing access to giant oil and gas fields; however, these fields must be found and this entails risk. This chapter looks at the background of how oil companies come to possess oil and gas 'properties' and the processes and players involved in their development.

Bids and Blocks

Acreage, blocks and concessions all refer to a legally recognised interest in an oil and gas property. This is surrendered by a land owner in exchange for royalties and other considerations. Despite the fact that most oil and gas deals are confidential business transactions, almost all are bid for openly. The final contract and choice of the oil company will depend on the nature of the land owner and development complexity[1].

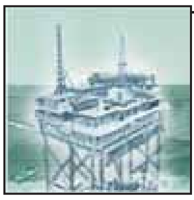
Land Owners

Governments have different obligations from institutions, which in turn have different needs to those of private individuals. Governments are driven by a much wider agenda ranging from economic sustainability, ob-

FPSO Platforms - *Floating, Production, Storage and Offloading vessels (FPSOs) can process and store crude oil, and offload the oil and/or natural gas. A process plant is installed on the ship's deck to separate and treat the fluids from the wells. After the crude is separated from the water and gas, it is stored in tanks on the actual vessel and then offloaded to a relief ship every so often.*

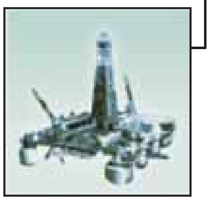
The relief vessel is an oil tanker that moors on the FPSO stern to receive the crude stored in its tanks and then transport it onshore. Compressed gas is sent onshore through gas pipelines and/or injected back into the reservoir. The larger FPSOs have a daily processing capacity of some 200,000 barrels of oil, with an associated gas production of approximately two million m^3 a day.

Round-Hull FPSO - *This is a pioneering FPSO platform due to its round-hull shape, and the first to produce, store and offload oil. The platform produces in deep waters, ranging from 1,000 to 1,500 metres. The round shape increases stability in the sea, since the waves circle the vessel. Its hull, made out of two layers of steel plates, is more versatile and stable, allowing operation under much more severe environmental conditions and affording the vessel more safety with regard to oil leakage into the sea.*



Fixed Platforms - *These were the first units to be used. Preference has been given to them in fields located in water depths to 200 m. Fixed platforms generally consist of modular steel structures installed at the operation site with piles driven into the seabed. Fixed platforms are designed to receive all drilling equipment, material storage, and staff accommodation, plus all well-production facilities.*

Jack-Up Platforms - *These consist basically of a barge fitted with a support structure, or legs that when activated mechanically or hydraulically, are lowered until they reach the seabed. The platform is then raised above the water level to a safe height, away from the action of the waves. These platforms are mobile and are pulled by tugboats or are self-propelled. They are designed to drill exploratory wells on the continental shelf in depths varying from 5 to 130 m.*



Semi-Submersible Platforms - *Semi-submersible platforms consist of a structure of one or more decks supported by submerged pontoons. A pontoon moves in accordance with the action of waves, currents and winds, and this may damage the equipment that is to be lowered into the well. That is why it must be set in position on the surface of the sea, within a tolerance radius dictated by the sub-surface equipment. Two kinds of system are responsible for positioning the pontoon: the anchoring system and dynamic positioning system.*

The anchoring system consists of 8 to 12 anchors and cables and/or chains, like springs that produce efforts that can put the pontoon back in position when it is moved by the action of the waves, winds and currents.

In the dynamic positioning system, there is no physical connection between the platform and the seabed, except in relation to the drilling equipment. Acoustic sensors determine the driftage, while the computer-controlled propellers in the hull bring the platform back into position.

Semi-submersibles may or may not be self-propelled. In any event, they are more mobile and are preferred for drilling wildcat wells.

Drill Ships - *A drill ship is a vessel designed to drill subsea wells. Its drilling tower is located midship, where an opening in the hull allows the drill string to pass through. The drill ship positioning system, consisting of acoustic sensors, propellers and computers, cancels out the effects of the wind, waves and currents that tend to move the ship from its position.*

Figure 1 - Types of Platforms (Courtesy of Petrobras)

ligations to future generations and social responsibility. Institutional and private individuals are generally more concerned with a Return on Investment (ROI) within a given time period[2].

Development Complexity

The cost and complexity of a particular development depends on its location, size and the extent of geological knowledge. If the lease is offshore, greater complexity and cost will be added. This is because offshore fields require more capital, technical expertise and logistical planning than onshore fields. The rule of thumb is the greater the water depth, the greater the complexity and cost, as higher specification rigs are required.

Developments that are located in shallow waters (defined as up to 1,500 ft or 500 m water depth to the seabed) may use fixed platforms. Greater complexity is associated with developments located in deep seas (up to 6,560 ft or 2000 m of water) as they require tension leg platforms or semi-submersible rigs. The greatest technical and financial challenges are linked with ultra-deepwater developments located in water depths of 8,200 ft (2500 m) or more. In these water depths, semi-submersible facilities or Floating Production, Storage, and Offloading (FPSO) vessels are required[3].

Block size will also add complexity and cost. Typically, offshore Gulf of Mexico (GOM) blocks are nine square miles in size. Offshore North Sea block sizes vary between 230 and 460 square miles. Blocks in new exploratory frontiers can be much larger. Exemplifying this are Brazilian exploratory blocks such as those in the Foz de Amazonas which can be 2000 square miles in area. Locating reserves in such a large area is no mean feat.

Where geological knowledge exists, exploration risk is reduced. Where previous wells have been drilled, reservoirs and conditions have been characterised and this acts as a guide to future drilling; however, in wildcat or exploratory wells where reservoir characterisation is not present, complexity, cost and risk are increased.

Royalties

A 'royalty' is an interest in an oil and gas lease that gives the owner of the land the right to receive a portion of the production from the leased acreage or proceeds from the sale of production. This generally does not require the owner to pay any portion of the costs of drilling or operating the wells on the leased acreage. Royalties may be either land-owners' royalties or overriding royalties. Land-owners' royalties are reserved by the owner of the leased acreage at the time the lease is granted. Overriding royalties are usually reserved by an owner of the leasehold in connection with a transfer to a subsequent owner. Royalties can vary from 100% in the case of national companies, to 50% in joint ventures and to as little as 10% in mature assets. The level of royalty depends on the complexity of the development and investment required. Royalties are not necessarily the most important aspect of an oil and gas deal as creating local content and infrastructure maybe equally important[4].

Producers seek exploration and development assets in order to maintain a return to shareholders. Market watchers apply considerable weight to proved reserves and production when analysing share values. They are the long-term measure of an oil company's health, while daily production represents short-term cash flow.

Portfolios Balance Risk

How do oil companies routinely back some of the most expensive and risky ventures on earth (i.e. deepwater exploration drilling) and still make profits? Oil companies can sustain the heavy losses of a wildcat (drilling for unproven reserves with limited geological knowledge) because they have a portfolio of assets generating cash. This is usually managed on the basis of markets, geography and economics. Oil companies employ geological modelling, offset data and exploratory wells to pinpoint reserves. Both oil companies and concession holders use due diligence systems to appraise certain blocks (a lease area inland or offshore) according to historic finds to date or the likelihood of finding oil and gas. Where no wells have been previously drilled, the oil company will drill a wildcat. This represents the highest degree of risk, but can be balanced with finds and production from other mature assets generating cash. The portfolio is usually split along regions, countries and assets. It is here that market conditions prevail. Oil companies will use financial models that take into account the future value of hydrocarbon reserves at different barrel price scenarios and demand. Oil companies will apply financial models assessing economic and production variables such as the '3 Ps' and the present value of reserves[5].

Gaining a Concession

Land owners attract attention to prospective offerings or licensing rounds by informing industry analysts and firms specialising in oil and gas leases. They may also conduct 'road-shows' where key members of the land owners management will present 'upstream opportunities' at industry events such as the International Petroleum Conference, the World Petroleum Conference and at financial centres around the world.

Subsequently, and without exception, all land owners will pre-qualify companies with an invitation to tender. Strict technical and financial criteria are applied before this initial application for a concession is accepted. In this way, concession holders (governments, institutions or private individuals) can screen prospective oil companies or 'operators' to see that they are actually capable of meeting the challenges associated with the exploration and production of hydrocarbons and pay the all important royalties.

Once a prospective operator has been qualified, they can then proceed to the next stage. Qualification leads to bidding or negotiating the contract for lease acquisition. Further steps will be seismic permitting, lease option negotiations, and preparing pooling and unitisation agreements. It should be noted that unitisation agreements are usually only entered into after discovery and some production has taken place. This usually occurs when the collective area operators realise that their field can produce more oil as a single unit rather than several sub-units. Negotiating a unitisation agreement is incredibly complex, particularly in the case of land leases where a large number of land owners are involved. Typically, this is an open auction, sealed bid or a negotiated deal. Open auctions are competitive bids

> Negotiating a unitisation agreement is incredibly complex, particularly in the case of land leases where a large number of land owners are involved.

for leases, sealed bids are posted and closed negotiations are held between parties. Each has its merits and downfalls; sometimes more can be negotiated off the bidding table rather than on the table[6].

'Producers-88' Lease Form

Although there is no standard form of oil and gas lease, a common form for US oil and gas leases is known as the 'Producers 88'. The name arises from an oilman or 'producer' who was seeking to purchase a lease. This producer had a certain deal in mind, but had no printed contract outlining the terms and conditions. The oilman sought a printer's shop to get the form printed. The printer's foreman needed to give the printing job a name and pencilled in 'Producers-88' to the job referring to its sequence in the press. Due to an oversight, the pencilled reference was printed on the upper left-hand corner and the name stuck, 'Producers-88' lease form.

Not every producing company used the same printer, but anecdotes show that many farmers (land owners holding the title deeds) would only sign a 'Producers-88' form of lease. Consequently, majors, independents and 'land-men' had their own forms of leases printed, many of which were similar in content, but all of which had 'Producers-88' printed in the upper left-hand corner.

The pre-printed form of lease typically presented to a mineral owner has basic terms and provisions such as the name of the land owner and oil company, the description of the land, the duration of the lease, the amount (fraction or percentage) of royalty, the name of the depository bank for the payment of rentals, and the amount of rentals (if it is not a paid-up lease)[7].

'Paperweights'

There is no single form of lease that meets all land owners' specific needs. Each lease is a bulky set of documents prepared on an individual basis. Usually, the oil company will have to accept the bid lease conditions offered, but in certain cases (i.e. for a multi-billion dollar investment) negotiating leeway exists. Conditions will cover the granting of a lease, royalty, shut-in well, pooling and unitisation, delay rental and partial release, operations and offsetting production, assignment, warranty, and force majeure clauses.

On entering an oil concession, the land owner and oil company have different interests. The land owner is interested in gaining as much bonus, royalty and terms such as local capability as possible. The oil company is interested in limiting its obligations to the land owner and wants the lease to contain terms that are as broad as possible. In most instances, the parties will compromise to reach a mutually acceptable middle ground and a contract will be signed[8].

Bargaining Power

As in all business transactions, the party with the greater bargaining power and knowledge sets the terms. It has been said that governments, at times, can be at a negotiating disadvantage when dealing with International Oil Companies (IOCs). At any given time, IOCs can draw on a much wider knowledge base of global trading conditions. In contrast, a national government is limited to national conditions. This was part of the rationale for the nationalisation of petroleum in many countries and the formation of the Organisation of the Petroleum Exporting Countries (OPEC). Nonetheless, land owners will always hold the upper hand because they 'own' the oil and gas reserves. Oil companies need reserves to keep trading so they are willing to 'buy' the technical and financial risks associated with exploration and pay royalties; however, neither can profit without the other as there is a mutual need.

Today, gas exporting countries have formed alliances to share information on global gas trends. This experience shows that granting access to oil and gas rights are strong bargaining tools which can help obtain benefits beyond royalties[9].

The Oil Is Ours… But You May Develop the Gas

Some twenty-five years ago, the Saudi royal family finished the process of re-nationalisation of the country's oil and gas reserves. This allowed Aramco, the national oil company, to join a growing group of oil companies and countries that re-nationalised their hydrocarbons; for example, countries such as Mexico, Venezuela and Iran. By some accounts, between 1970 and 1976, nearly 20 countries asserted their national sovereignty over their operations. Driven by the need to develop gas reserves (to meet the growing demand for gas and to keep oil for exports), many countries have slowly relaxed their national controls. This has been accomplished through joint ventures, contracts with service companies and ownership licences which allow larger oil companies to return to previously nationalised oil markets[10].

Many types of oil and gas contracts exist. In this section, we consider the process of selecting and contracting oilfield service companies.

It is worth distinguishing oil and gas operating contracts from service and supply contracts. We have already

Rank	Company	500 Rank	Revenues ($ millions)
1	ExxonMobil	2	347,254.0
2	Royal Dutch Shell	3	318,845.0
3	BP	4	274,316.0
4	Chevron	7	200,567.0
5	ConocoPhillips	9	172,451.0
6	Total	10	168,356.7
7	Sinopec	17	131,636.0
8	China National Petroleum	24	110,520.2
9	ENI	26	109,014.2
10	Pemex	34	97,469.3
11	Valero Energy	43	91,051.0
12	Petrobras	65	72,347.0
13	Statoil	78	66,280.3
14	Repsol YPF	90	60,920.9
15	Marathon Oil	92	60,643.0

Table 1 - The 15 Top Oil Companies as Listed by the Forbes Fortune 500 Group

seen how operating contracts provide a framework for paying hydrocarbon production royalties (bids and blocks). Now, we can consider how service contracts enable the supply of equipment and technical services that are necessary for hydrocarbon production.

Outsourcing

Traditionally, oil companies whether IOCs, NOCs or independents have always out-sourced certain oilfield activities, such as rig supply or facilities engineering. As the industry consolidated in the 80s and 90s, the volume of outsourcing increased as new definitions of non-core activities were applied to a greater number of activities and disciplines. Nowadays, non-core activities are defined differently according to the discipline and oil-company in question; however, the common thread that emerges is that all disciplines will have at least some outsourced elements. This means that any given oil company will have service providers in many different areas of activity. The extent of actual outsourcing depends very much on the culture of the oil company, the degree to which a task is defined as core and its accompanying level of commercial sensitivity.

Core Activities

Facilities engineering, for example, is an area that is traditionally outsourced. Certain oil companies, however, may consider production or drilling and completions as non-core. In this case, an oil company representative will act as a project manager, but the actual engineering is conducted by a lead service company and a number of sub-contractors. Other oil companies may consider disciplines such as reservoir management as core areas, or as sensitive functions, and therefore not wish to outsource the service. Almost all operators consider exploration and reservoir management as core to their operations because these two activities can make or break a company[11].

Major oil and gas disciplines are classed as:
- Facilities (platforms)
- Drilling and completions
- Production
- Reservoir engineering
- Health, Safety and Environment (HSE)
- Management systems (IT and Accounting)
- Project management, and
- Project economics/financing.

Oil Service and Supply Companies

Fortune 500 Top 15 Oil Companies

Table 1 shows the top 15 oil companies that are listed by the Forbes Fortune 500 group and floated on the New York Stock Exchange (NYSE) or other American stock markets as of 2007. With the fall of the Oil Curtain, we can expect more NOCs such as Sinopec, CNPC, Petrobras, Pemex and StatoilHydro to move higher up the table.

Many of the large service companies are floated on the Philadelphia Stock Exchange; however, some companies such as Schlumberger, Halliburton, Baker Hughes and Weatherford are also listed on the NYSE. The Philadelphia exchange runs an Oil Services Index (OSX^{SM}) which is price-weighted and comprise companies that provide oil drilling and production services, oil field equipment, support services and geophysical/reservoir services. The OSX commenced trading on February 24, 1997.

Some OSX companies are:
1) Baker Hughes Inc. (BHI)
2) R&B Falcon Drilling Company, Inc. (FLC)
3) Global Industries Ltd. (GLBL)
4) Halliburton Co. (HAL)
5) Nabors Industries Inc (NBR)
6) Noble Drilling Corporation (NBL)
7) Rowan Companies, Inc. (RDC)
8) TransoceanSedcoForex (RIG)
9) Smith International Inc. (SII)
10) Schlumberger Ltd. (SLB)
11) Tidewater, Inc. (TDW), and
12) Weatherford (WFT).

National Factors

Many service companies can trace their origins to as far back as 50 years ago, and in some cases, as much as a century. These companies will have built up strong positions in technological niches and markets through organic growth as well as acquisitions. Their positions will be based on local applications, relationships, investment and management philosophy.

Variations in market presence occur due to political situations, governmental policy and the trading regulations between countries; therefore, certain service companies will be stronger in certain markets and enjoy a leadership position, while in other geographic areas they will have only a skeletal presence. In this way, the service sector tends to balance itself out globally with the larger companies tending to consolidate their market share in certain areas while being weaker in others. This occurs with giant service companies such as Baker Hughes, Schlumberger and Halliburton. One or more of these service companies may have a large market share in Latin America and the North Sea, while having a reduced presence in the Middle East. By the same token, the other service company's operations will reflect the opposite; it will have a stronger presence in the Middle East and a lower presence in other areas[12].

Operator Type

Large IOCs such as Shell and BP will always tend to favour centralised service agreements due to the high number of operating assets these companies hold. A central procurement contract offers global supply and pricing advantages which will have been negotiated by a head or regional office with bulk volumes in mind. Many such contracts exist and are aptly named such as the 'Big Lever', 'Preferred Contractor' or the most popular term these days, Master Service Agreement (MSA). The oil companies will also appoint local focal points which enable the contracts and services to be managed more effectively and in accordance with local needs.

For certain products that can be bought in bulk such as casing, bits and drilling fluids, this provides certainty of business on both sides. Independents may also develop global preferred service agreements but, due to a much smaller number of operating assets, their contracts will be less centralised and will tend toward establishing contact with major service companies on location[13]. Sometimes smaller oil companies may form 'co-ops' to purchase commonly-used items in bulk to get a low price. They usually do this thorough the auspices of an area supply store.

Process of Selection

Despite the oil and gas industry being highly globalised, most of the factors that influence the selection of contractors are locally based. These include variations from nation to nation, operator type, the extent of goodwill between companies, technical innovation and price. The actual selection of contractors is a complex process that requires oil companies to appoint a project manager or other executives to act as a tender board in order to prepare a contracting strategy.

This document will cover: the prequalification of tenderers; a finalised bidders' list; finalised technical and commercial specifications; the preparation and issuing of a tender document; bid clarification; issuing of clarifications and addendum to tenderers; prepation of company estimates; the evaluation of technical and commercial bids; presentations to the project manager or tender board; presentations to the Ministry that deals with oil and gas leases; the awarding of contracts; start up (mobilisation); and budget calculations among other things. Corporate governance, ethical standards and local content targets are also often included[14].

Typically, IOCs will employ a global focal point or a project or technology leader with responsibility for the contracting strategy and direction. Each region or major asset will also have a local specialist or focal point. This local specialist will have a local service company counterpart. Other staff will include service personnel seconded to the oil company's local offices[15].

National Oil Companies

NOCs are more likely to contract long-term services and develop partnerships with service companies. NOCs, despite the perception to the contrary, provide many of the most lucrative service contracts. The predominant philosophy or perception is that 'the lowest price wins'. This may be applicable in some cases, but in general, the NOCs often offer long-term fixed revenue contracts, something that IOCs rarely offer.

Some NOCs are obliged under the laws of their country to accept the low bid. This can cause problems as many fly-by-night companies deliberately lower a bid to get the work or concession and try to figure out later how they are going to fulfill its terms.

Goodwill

This concept covers global relationships that permit the exchange of technology, knowledge and operational know-how. These relationships exist at many levels. Some oil companies use bulk-buying contracts to supply international operations, while others use Joint Industry Projects or JIPs. Other oil companies rely on technology cooperation agreements and personal relationships with their service company counterparts and small specialised companies.

Small companies may not achieve large economies of scale, but at the same time they do not have large overheads. Because they can act rapidly, they can often beat the giants when it comes to developing new technology. Operators develop technology in-house through JIPs and with best-in-class companies; for example, Shell and Petrobras respectively are involved in the monobore and the Procap 3000 initiatives which are two examples of technology cascading downward.

Underlying the monobore (a vision of drilling and casing a single-diameter well from top to bottom) was the creation of two businesses to develop the downhole tools, tubes and markets for expandables. Procap 3000, a range of exploration and production technologies, is paving the way in ultra-deepwater development. Drilling contractors have introduced simultaneous drilling and completion of two wells by way of the

"Small companies can distinguish themselves by providing a service that includes applications analysis, technical recommendations and rig-site support through end-of-well reporting."

dual-activity derrick system. Additionally, the billion-dollar think tanks and research and development facilities that major service companies own are continually creating new technologies.

So how do small companies compete against this backdrop? How do they succeed without the benefit of marketing channels or the influence of larger service companies?

Small companies can distinguish themselves by providing a service that includes applications analysis, technical recommendations and rig-site support through end-of-well reporting[16].

If they can maintain market leadership, they will attract the attention of operators interested in new technology. Certain oil companies select market leaders in what they deem essential technology and work with those leaders to develop new technologies (tough luck if you're not No. 1) .

Tangled Thicket

Traditionally, the oil company appoints a lead service contractor who may or may not be responsible for naming a drilling unit provider. The complexity of the drilling unit required will also affect whether this decision is made by the lead contractor or oil company. Drilling units (e.g. drillships, jack-ups, semi-submersibles or land rigs) will vary according to offshore and onshore needs. Subsequently, specialist contractors in each activity of each discipline are selected. As very few companies can provide all the required services, the concept of integrated contracting becomes commonplace. An integrated contractor or contracting alliance allows for each party to calculate their share of the development cost and price. These calculations are then used as performance targets, with the gain or pain of reaching or not reaching the target being shared. For operators fed up with the tangled thicket of contracts and contractors, the easiest course may lie in integrating outsourced services. This certainly reduces some of the complexity and numbers of service providers by providing a single point of contact. The appropriateness of integration, however, is very much dependent on the location and nature of the project; for example, the right approach for a development in China is probably inappropriate for Brazil. Other examples include the US GOM and the UK North Sea where contracting differs from practices.

Critics would argue that integration tends to discourage small-company services, as the main service provider will fulfil most technology requirements in-house. Only where technology is unavailable can a small company enter the project, filling a gap that no other business can.

Integrated services often mean small companies are required to meet wide-ranging legal or other tender requirements, many of which are applicable only to the major service provider. While safety is non-negotiable, it seems unfair to insist on the same levels of insurance liability for two different scopes of services. This asks small companies to bear more project risk without an accompanying increase in the reward[17]. Recently, IOCs have recognised the benefits of 'chain-of-accountability' and weigh this highly in contractor selection. Instead of dealing with a myriad of small providers, they limit their contracts to a few large, integrated service providers. If anything goes wrong, there is no finger-pointing. The contractor takes responsibility and fixes the problem.

Price—Market Cycles

Market cycles affect pricing more than any other aspect. In terms of tender strategy, an operator may use price competition as a way of controlling costs. In a down market, demand falls while the need to maintain utilisation remains. Here price-beating, where the lowest price wins, may be adopted by the service company to retain work. In an up-market, demand is increased and there are greater demands on utilisation; therefore, price competition is counter-productive as companies will tend not to provide services or equipment as they are diverted to the highest-paying markets.

Performance Pricing

How does one reward so many different service companies? Perhaps this is where value or performance pricing can help. The operator and small company set a performance target and price the work accordingly. If the contractor overachieves, they receive a proportion of the gain.

Conversely, if the contractor underachieves, they invoice less than the original price. It is self-evident that operators and small companies need to work more closely in developing cost-lowering technology. Increasingly, drilling engineers are becoming project managers rather than specialised engineers. Essentially, it lies with the service provider to effectively market service benefits to the operator.

This is where small companies trip up. Without established marketing channels, small companies regularly miss out on opportunities. Operators can help by focusing a small company's resources on specific projects where applications are plentiful. Cynics would argue operators are not in the business of making small companies richer, but this misses the point.

Sign-posting a project helps accelerate product development and operator savings. To that end, small companies must improve their marketing to demonstrate service benefits.

They must also develop partnerships with operators and be service-oriented rather than supply-oriented. Operators need to keep on the lookout for small companies, invest in their technology and encourage integrated service providers to use their services. Last, but not least, everyone must reassess how the reward is spread across the hydrocarbon machine[18].

Bundled or Bungled Services

It's easy to see the attractions of 'bundling' services. By integrating contracts for equipment and services, you can reduce suppliers and paperwork. In this way, fewer demands are made on your time, there is less paperwork, and there is less debating over which tool caused the trip.

Bundled contracts, however, can quickly become 'bungled' if individual Bottomhole Assembly (BHA) components and their risks are not isolated. Everything hinges on achieving a balance between risk and reward[19].

Service companies have been saying for years that the scales have tipped the wrong way. As in the past, oil companies still own acreage and all the geological or other problems it may have. Whether the reservoirs are hard-to-access, hard-to-locate or bounded by hard-to-drill formations, the challenges are inherited by the oil company. Yesterday's IOCs, that mainly kept their full internal Research and Development (R & D) facilities, could grapple with the difficulties by using in-house R & D 'greenhouses'. Shareholders didn't mind this. In fact, it was universally agreed that R & D investment was a way of maintaining a competitive edge; however, many modern oil companies do not necessarily have this resource any longer.[20].

Consolidation in the oil industry drove this change. Profits could be handsomely boosted by reducing expenditure in various things, not least in-house R & D. Today's IOC must look outwards for technology and this where the service companies fit in perfectly.

The service company's concern—read gripe, if you are an operator—is that although they solve an increasing number of operator 'owned' problems, and run R & D facilities previously only undertaken by operators, rewards have remained constant over the years. Sure, rental or operating rates for equipment increase annually or have a premium according to location, but these are localised factors rather than a redistribution of reward based on risk acceptance and investment in research.

Everybody agrees that maximising oil production is the most important and valuable activity for the operator; however, nobody agrees about how to define and apply the true value of a particular activity. Mostly, the industry does simple maths: costs plus margin equals price. This, however, omits the true value delivered—or not—to the operator[21].

If you don't deliver, you get hit with the penalty, a lower value invoice. While this sounds good in theory, there are drawbacks. Standard drilling service contracts allow for separated BHA component risks. That's a grand way of saying if you're a drill bit (or other) company and some other downhole tool screws up, your final bit invoice won't be affected. And quite rightly—why should it? If the bit is performing fine, but a trip is caused by another element in the BHA, the bit company won't lose out.

In an integrated contract, this type of situation causes losses at an operating/meterage and at an overall performance level. Let's continue the example. Not only does the bit company suffer a loss in revenue due to another BHA component's failure, but there is also a lower overall performance for section drilled time. This invokes a penalty clause and it is not so easy to claim extenuating circumstances if all the equipment is supplied under a single company's service contract.

Things get even more complicated with the contracting of third party niche suppliers. If the equipment doesn't work properly, who bears responsibility? Worse still, what happens if this malfunctioning leads to a stuck fish or Loss-in-Hole (LIH)? On the note of LIH, it's worth straying a bit. It can be said that LIH prices are high. Certainly, a tool that is new and has only seen a few hours downhole will always have a high LIH price because this is a function of future revenue loss. Conversely, you must account for depreciation. If the tool had many hours utilisation, it should have a much lower value.

Let's get back to our stuck fish. It causes a sidetrack and a heavier than expected LIH invoice. Bang goes any incentive for the bit's good performance. Who bears the responsibility? If the Authority for Expenditure (AFE) is exceeded, who pays the difference?[22]

These are tough questions and some might say somewhat extreme; however, they are based in reality. Although using a main contractor approach where a single company drills and completes the entire well is not yet commonplace, this is a growing trend. The remaining dilemma is as follows: how can risk and reward be shared between the many different service components?

Perhaps performance pricing can help. The operator and main contractor set a performance target and price the work accordingly. If there is overachievement, all receive a proportion of the gain. Conversely, if a component company underachieves, it invoices less than the original price and takes a proportion of the loss. Performance pricing would reflect costs (e.g. R & D manufacturing, tool wear and tear, etc.) and some part of the value delivered to the client[23].

An appreciation for the dilemma faced by operators has been a long time coming. For many years, oil company departments were semi-autonomous and had little regard for the other departments in the company. The drilling department was responsible for drilling a hole in the ground and casing it. The hole (one could hardly call it a well at this point) was then turned over to the completions department. The drilling department started to drill the next well, leaving the completions department to remedy such problems as formation damage caused by poor drilling fluid selection, bad cement jobs, damaged casing or wellhead problems.

The formation of asset teams alleviated these problems. By holding every member of the asset team responsible for the asset and rewarded solely based on the asset's performance on production, people such as drillers suddenly got a stake in the end result, and their sloppy performance came back to bite them in cost overruns or curtailed production performance; a lower asset profitability meant a lower bonus for them. The same fate awaited the geology department whose sloppy work caused a well to be drilled in the wrong place.

We know who the major players are in the oil industry and how they came to acquire their 'properties'. Now we need to know how do asset teams strike oil?

References

1. Land and Leasing ISBN: 0-88698-094-1 PETEX 1984.

2. Well Planned, Brazil Oil and Gas Issue 5 Wajid Rasheed.

3. These are generic rules for ease of classification.

4. This will depend on the land owner's priorities.

5. The API Specification Database The American Petroleum Institute Specification Database Software™ provides a knowledge-management toolset for the project engineering team. Facilitates the entire equipment specification process including the entry of process data and design to the final entry of mechanical data sheets and development of the technical bid specification package.

6. Dependent on the oil company and land-owner involved.

7. May vary from lease to lease.

8. Negotiation plays as important a role as the bid.

9. Such as building local content.

10. Such as Brazil, Mexico and Saudi Arabia which all had monopolies.

11. Fundamental to asset management.

12. From the 30 countries I have worked in this is very much the case.

13. Idem.

14. Corporate governance requirements are often stipulated as contractual terms.

15. Also known as in-house engineers.

16. Harts E & P Mar 2002 Drilling Column Wajid Rasheed. 'Small companies and tangled thickets'.

17. Idem.

18. The reassessment of risk and reward seems to have stopped at percentage of value delivered or percentage operational cost.

19. Harts E & P Mar 2002 Drilling Column Wajid Rasheed 'Small companies and tangled thickets'.

20. Although this may change as IOCs seek to differentiate themselves. Shell selects certain start-ups through its technology ventures (STV).

21. Harts E & P Mar 2002 Drilling Column Wajid Rasheed 'Small companies and tangled thickets'.

22. Harts E & P Jun 2004 Drilling Column 'Bundled or bungled services?'. Advocates balanced integrated services contracts.

23. In a low oil price some service companies may prefer to take greater risk. Others would shun this as unthinkable.

OGEP 2010
The 2nd Saudi Meeting on
Oil and Natural Gas Exploration
and Production Technologies
KFUPM Campus, Dhahran, Saudi Arabia
December 18 - 20, 2010
Call for Abstracts
Academia - Petroleum Industry
Synergy for a Better Tomorrow
Organizers
وزارة البترول والثروة المعدنية
Ministry of Petroleum and Mineral Resources
The Kingdom of Saudi Arabia
مدينة الملك عبدالعزيز للعلوم والتقنية
KACST

Invitation

The Ministry of Petroleum and Mineral Resources, King Fahd University of Petroleum & Minerals (KFUPM), and King Abdulaziz City for Science and Technology (KACST) cordially invite you to participate in the 2nd Saudi Meeting on Oil and Gas Exploration and Production Technologies (OGEP 2010). The Meeting will be held at the KFUPM Campus in Dhahran, Saudi Arabia, on December 18-20, 2010, under the auspices of His Excellency Ali Naimi, the Minister of Petroleum and Mineral Resources.

The theme of the meeting is "Academia Petroleum Industry: Synergy for a Better Tomorrow." The theme was selected to focus on enhancing the collaboration between academia and industry in research and development and to prepare a competent workforce for the future.

The OGEP 2010 will include technical sessions covering both oral and poster presentations, invited speakers, panel discussions, young professionals session, student paper contest, and an exhibition covering the latest advances in oil and gas exploration and production technologies.

The meeting is designed to provide a forum for discussion of a broad range of topics relevant to academia and E&P industry, including business relationships between academia and industry, human resources, exploration, production, drilling, reservoir, health, safety & environment, economics and energy. We particularly encourage the presentation of case histories, innovative ideas, challenges, and new technologies, as this is an excellent platform to exchange actual experiences and/or showcase of new and innovative solutions with participants from local and regional academia as well as industry leaders from National and International Oil Companies (NOC/IOC) like Saudi Aramco, Chevron, and Shell as well as leading service providers such as Baker Hughes, BJ Services, Halliburton, Schlumberger, and Weatherford.

On behalf of the Technical Committee, I would like to invite you to participate in the OGEP 2010 through submittal of abstracts. I also ask for your support in distributing this announcement to colleagues and friends.

Chairman of the Technical Committee
Abdulrahman S. Al Jarri, PhD
Saudi Aramco

Co-Chairman of the Technical Committee
Abdulaziz A. Al-Majed, PhD
King Fahd University for Petroleum and Minerals

Objective

The meeting is organized for the academic community and the petroleum industry to discuss and collaborate on oil and natural gas exploration and production technologies. The meeting will provide a unique opportunity for professionals, experts, scientists, and faculty members in these fields to discuss and exchange their views and experience, with an emphasis on synergy between academia and the industry on relevant topics including human resources, research and development.

Topics

The technical program will cover numerous topics relevant to academia and oil and natural gas exploration and production including (but not limited to):

- Academia and Industry Business Relationships
- Human Resources
- Exploration Technologies
- Petroleum Geology and Reservoir Characterization
- Reservoir Related Technologies
- Production Technologies
- Drilling Technologies
- Health, Safety, and Environment
- Economics and Energy

Details of areas of interest are in the attached table.

Call for Abstracts

The Technical Committee solicits participation from international and local professionals, experts, scientists, and educators through submittal of extended abstracts (up to 4 pages) for technical presentations and posters.

Submittal Instructions:

1. Extended abstracts (minimum 1000 word and up to 4 pages) must be received no later than June 2, 2010.

2. Submissions should be in English and should briefly state the objectives, methodology; application conclusions of the work and future follow up if any.

3. Extended abstracts should be submitted using the attached Abstract Submission Form online through the OGEP 2010 Web Site: http://www.kfupm.edu.sa/ogep2010/ or www.OGEP2010.org and an auto-reply confirmation email will be sent to each submitter.

4. Accepted extended abstracts will be given the opportunity to submit full manuscript for publication, or published as submitted, in meeting proceedings and any other meeting's information media, including the website.

5. Selective papers might be peer reviewed by KFUPM for potential publication in the Arabian Journal for Science and Engineering (AJSE) published by King Fahd University of Petroleum & Minerals in Dhahran, Saudi Arabia after meeting the journal's publication guidelines.

6. Authors are responsible for obtaining necessary clearance from their management, partners, and government agencies (as applicable).

7. Papers may be submitted for oral or poster presentations, and the type of presentation must be stated with the abstract submission.

8. An abstract submission form is included opposite and can also be downloaded from the meeting web site.

9. In case of several contributors, the principal author for correspondence should be designated.

Deadlines

Abstract submittal deadline: June 2, 2010
Acceptance Notification: July 7, 2010

Panel Discussions

The OGEP 2010 will include three panel discussions with the following tentative subjects:

- Academia and the Petroleum Industry: working together to supply future workforce
- Partnering Technologies for a Better Tomorrow: Academic and Industrial Prospective.
- Economic Exploration, Exploitation and Development of Tight Gas

Exhibition

The venue of the Meeting will host an exhibition, to take place at the same time as the conference. The exhibition will showcase the latest technologies available in the market for oil and natural gas exploration and production including hardware, software and services. An announcement for the exhibition will follow soon.

Young Professionals' Session

The Technical Committee is delighted to introduce a Young Professionals Session in the OGEP 2010. This session will be fully dedicated to participation by young professionals who are less than 35 years in age. The main objective is to create a network that allows young professionals to share their experiences, discuss career issues, ideas, events, and best practices in the petroleum industry. The Technical Committee encourages and seeks participation of young professionals through submittal of extended abstracts for presentation from local, regional and international institutions and companies.

Student Paper Contest

A student paper contest will also be held during the OGEP 2010. This is to attract students from various colleges and universities in the Gulf and the Middle East region. More information is available in the attachment.

Field Trip and Tours

A half-day field trip covering some geological landmarks of the Eastern province will be planned and there will be tours to operating and R&D centers in the area.

OGEP 2010 Students Contest Information

Contest Objective

To allow graduate and undergraduate students from local and Middle East Universities to propose, on a competitive basis, innovative ideas, design concepts and new enabling technologies that are relevant to the E&P industry. The contest consists of selected students or teams (undergraduate, master, and PhD divisions from participating universities). The work of each student or team will be judged for content and presentation by a panel of experts according to the guidelines below. The contest will take place during the OGEP 2010 to be held in Dhahran, on December 18-20, 2010.

Contest Participants

Interested universities from Saudi Arabia and GCC (or Middle East) countries are invited to promote the contest through participation of their graduate & undergraduate students. Each university department is entitled to present one student (or team) from each division. Accordingly, university departments (Petroleum Engineering and Earth Sciences) are encouraged to screen potential representatives internally before suggesting one for the competition. Nominees could be composed of undergraduate and graduate students. Participation of PhD students is allowed up to one per team. Each participating student or team will be supervised by one or more university professors who also act as "Student/Team Advisor(s)." Each team should have a "Team Leader" student who will also act as the main contact person for the contest.

Contest Topic

Participating universities may wish to choose any topic that is relevant to E&P Industry. However, when choos-

OGEP 2010

السعودي الملتقى
الثاني
تقنيات

Extended Abstract Form:

In order to ensure publication on the CD-ROM, authors should submit their abstract online:

Title:____

Extended Abstract (minimum 1000 word & up to 4 pages): (please state objectives, methodology, application and conclusions)

Please specify the most appropriate technical category related to your abstract from the attached Technical Categories List:

Primary Technical Category: ______________________________

Secondary Technical Category:______________________________

Please indicate whether your extended abstract is for oral or poster presentation (please tick one):

☐ Oral: I am willing to do a poster presentation in case an oral presentation is not possible. Yes ☐ No ☐

☐ Poster

☐ I would you like to submit: a paper or an extended abstract for the meeting proceeding.

Please list names in the order they should appear in publication:

Corresponding Author Information:

Name:______________________________

Company/institute: ______________________________

Address: ______________________________

City/Postal code: ________________Country: ________________

Tel.No.: ________________ Fax. No. :________________

E-mail: ______________________________

Has material been presented previously? Yes ☐ No ☐

If yes, indicate place and date: ______________________________

Short Biography of Presenter: ______________________________

An auto-reply e-mail will be sent out upon successful submission

Technical Categories

1. Academia and Industry Business Relationships
- Academia versus Industry Perspective: Bridging the Gap
- Strategic Partnership for Maximum Returns
- Industry Oriented Academic Curriculum
- Training and Development
- Research and Technology Transfer
- HR capital
- University & High Institutes
- Internship
- Students Outreach
- Alliancing & Partnering
- Evolving Relationship between Academia & Industry
- Small & Medium Business Enterprise
- Applied Research to Commercial Development

2. Human Resources
- Coaching & Mentoring
- Education & Knowledge Sharing
- Outsourcing
- Practical Training, Development & Continuing Education
- Professionalism &Accountability
- Professional Certification
- Recruitment & Retention
- Succession Planning
- Technology Transfer
- Advances & Learning Techniques/Tools
- HR Development for E&P

3. Exploration
- Advances in Exploration Technology
- Geological Modeling and Basin Studies
- Deepwater Exploration Strategy
- Unconventional Reservoirs
- Tight Oil/Gas Reservoirs
- Fractured Reservoirs
- Applied Non Seismic Methods
- Case Studies

4. Production Optimization
- Artificial Lift
- Gas Lift, ESP, Beam, Pump, etc.
- Automation - Unmanned Platforms. Downhole Sensors Remote Well Surveillance, etc.
- Deliquification
- Integration: From Reservoir to Facilities
- Intelligent Pigging
- Modeling Gas Network
- Nodal Analysis
- Water & Gas Shut-Off Treatments
- Well Conversion
- Multiphase Metering & Pumping
- Debottlenecking

5. Drilling Technology
- Cementing
- Coring Technology
- Drilling and Casing
- Drilling with Casing
- Eliminating Drilling Surprises
- Fluids & Bits
- Slim hole, Coiled-tubing & Other Methods
- Underbalanced /Managed Pressure Drilling
- Well Control
- Wellbore Geomechanlcs
- Wellbore Stability

6. Completion Technology
- Completions
- Completion Fluids, etc.
- Expandable Tubular
- Formation Damage Management
- Intelligent Wells
- Monobore & Big Bore
- Sand Prediction & Control
- Stimulation
- Well Perforating

7. Offshore Technology
- Completions
- Development Options
- Drilling
- Flow Assurance
- Production Facilities
- Production Issues
- Subsea Completion
- Well Intervention

8. Extended Reach, Horizontal and Multilaterals
- Candidate Selection
- Drilling & Completion Methods
- Geo Steering
- Intervention
- Performance Prediction & Control

9. Petroleum Geology & Reservoir Characterization
- Reservoir Characterization Technologies
- Reservoir Modeling
- Geostatistics
- Geo-steering & Real Time Answers
- Rock Mechanics / Well Stability
- Core Analysis
- Fracture Characterization
- Pore Volume Assessment
- Rock Physics and AVO
- Case Studies

10. Formation Evaluation
- Petrophysical Technologies
- Carbonate/Clastic Petrophysics
- 3D Earth Models
- Advances in Well Testing
- Open, Cased & Slim Hole Measurements
- Mud Logging Technologies
- Saturation Monitoring
- Borehole Seismic
- Core Analysis & Petrophysics
- Imaging Technology
- Low Resistivity Pay/Thin Pay
- Measurement & Logging While Drilling
- Open & Cased Hole Methods
- Overlooked/Bypassed Oil Zones
- Tracer Flow Tests
- Wireline Formation Testing & Sampling
- Low Permeability Reservoirs

11. Gas
- C02 Storage/Sequestration
- Gas-Condensate Reservoirs
- Gas Development & Marketing
- Gas Storage
- LNG
- Tight Gas
- Sour Gas

12. HSE
- Bioremediation
- Discharge Issues/Limitations
- Downhole Separation and/or Disposal
- Emergency Response Planning/Management
- HAZOP Studies/Risk Management/ Safety Case Requirements
- Safety Behavior
- Security Issues
- Social Responsibility
- Toxic Waste Management
- Water & Solids Treatment & Disposal

13. IOR (EOR)
- Chemical, Thermal, Miscible Injections &Others (Microbial, etc)
- Heavy Oil Production
- IOR Techniques
- Water flooding, Gas Injection, Vibro Seismic, etc.

14. Information Management and Real-Time Monitoring
- Collection, Transfer, Archival, Reporting. Quality Control & Assurance
- E-business applications
- How much data is enough?
- Near Wellbore Characterization
- Neural Networks
- Applications & Benefits
- Real-time Data Analysis & Control

15. Reservoir Engineering & Management
- Description & Characterization
- Forecasting Methods
- Material Balance, Simulation etc.
- Fractured Reservoirs
- Reserves Assessment & Booking
- Reservoir Compaction & Subsidence
- Reservoir Continuity & Drive Mechanism in Deepwater – Reservoir Geomechanics
- Multidisciplinary Approaches
- Onshore Operating Centre
- Performance Monitoring
- Pressure Maintenance

16. Developing Seismic Technology
- Acquisition/Processing/ Interpretation Techniques
- 3D & 4D Seismic
- Seismic Inversion
- Borehole Seismic Methods
- Rock Physics, Seismic Forward Modeling and AVO/AVA
- Cost Effective Seismic Acquisition and Processing Practices
- Application of Seismic Attributes in Exploration and Reservoir Development
- Advances in Seismic Interpretation
- Cross-well Seismic
- Multi-component, Multi Azimuth Seismic
- Ocean Bottom Seismic
- Pattern Recognition
- Time Lapse
- Passive Seismic
- Recent Acquisition Techniques
- Advanced Seismic Data Processing Methods
- Seismic Imaging
- Near Surface Seismic
- Multiple Suppression

17. Economics & Energy
- Reserves Assessment
- Field Development and Optimization
- World Energy Outlook (Supply and demand)
- Energy prices & Markets (Oil markets and Natural gas markets)
- Project evaluation and Real Options
- Risk and uncertainty
- Energy Management, Efficiency & Security related Studies

18. Field Development
- Assets Life Cycle Depletion Plan
- Development of Mature Fields
- Fast-Track Developments
- Heavy Oil
- Marginal Fields
- Subsea Development
- Virtual Reality Techniques

19. Integrated Technologies and Case Studies
- Case studies should demonstrate the design and implementation of schemes to create or increase value.
- While successes are great and are usually what get attention, cases demonstrating failures and why a failure occurred, and lessons learned are welcomed.

ing topics, 'out-of-the-box' thinking is encouraged.

Contest Format

Participating students or teams will present their papers to a panel of judges during the OGEP 2010 in Dhahran. Papers are to be reviewed and judged for content and presentation in accordance with the selection criteria as per the scoring sheet prepared by the OGEP 2010 Technical Committee. The highest scoring student paper shall be recommended for the award. Where two (2) papers receive the same total score, the proposal which has the highest score in the highest weighted criteria shall be recommended by judges from Industry and/or Academia for the particular award. Where this is not

Members	Affiliation
Mr. Majed Hassan Badah	MinPet
Mr. Ameen A. Al-Humidi	MinPet
Dr. Abdullatif Al-Shuhail	KFUPM
Dr. Hassan Al-Hashem	KFUPM
Dr. AbdulAziz Loubon	KSU
Dr. Emad Al-Homadhi	KSU
Dr. Hassan Naji	KAU
Dr. Omar Almisned	KACST
Dr. Fahad A Al Ajmi	Saudi Aramco
Mrs. Hiba A Dialdin	Saudi Aramco
Dr. Hamoud A Anazi	Saudi Aramco
Dr. Mohammed G. Al Otaibi	Saudi Aramco
Mr. Matter J. Al-Shammery	Saudi Aramco
Dr. Patrick Allman-Ward	Shell
Dr. Paul Thompson	Chevron
Dr. Muhammed Badri	Schlumberger
Mr. Mike Hopkins	Halliburton
Mr. Jaafar Aluzri	Baker Hughes
Mr. Charles P. Kreuz	Weatherford
Mr. Jose Reyes	BJ Services
Mr. Abdullah S. Al-Muhaish	SRACO

possible to separate equally scored papers, a joint award shall be recommended.

Contest Award

An Award consists of a certificate, a trophy, and a monetary prize (SR 10,000 for the first, SR 5,000 for the second, or SR 7,500 each for joint award). The Award is for the winning student or to be shared amongst all members of the team and it will be presented by the OGEP 2010 Technical Committee Chairman.

OGEP 2010 Technical Committee Members

Chairman: Dr. Abdulrahman S. Al-Jarri, Saudi Aramco
Co–Chairman: Dr. Abdulaziz Al-Majed, KFUPM

OGEP 2010 Participants

It is expected that several local and international organizations to participate in the OGEP 2010. One of the major factors contributed to the success of OGEP 2008 was the participation of various organizations.

The following organizations participated in the OGEP 2008 technical program:

- Saudi Aramco
- King Abdulaziz City for Science & Technology
- King Fahd University of Petroleum & Minerals
- King Saud University
- Schlumberger
- Halliburton Services
- Shell
- Chevron
- Total
- South Rub Al-Khali Company LTD (SRAK)
- SAUDI ARABIA OIL AND GAS MAGAZINE
- EniRepSa Gas Ltd.
- Baker Hughes Inc.
- GETECH
- Spectraseis Technologies
- Egyptian Petroleum Research Institute (EPRI
- The University of Texas at Austin
- Azerbaijan National Academy of Science
- GeoTomo LLC
- CGGVeritas
- University of Oklahoma
- ENI E&P Div.
- King Abdulaziz University
- University of Houston
- Colorado School of Mines
- Imperial College
- LUKOIL Saudi Arabia Energy Ltd.
- Petroleum Deveolpment of Oman
- Centrilift
- LUKSAR

Saudi Arabia oil & gas
www.saudiarabiaoilandgas.com

Contribute to Saudi Arabia Oil & Gas during 2010

EPRasheed is looking for editorial submissions on the topics outlined in the editorial calendar. This can provide your company with the opportunity to communicate EP technology to the wider oil and gas community. Please send abstracts or ideas for editorial to **wajid.rasheed@eprasheed.com**

Preference is given to articles that are Oil Company co-authored, peer reviewed or those based on Academic research.

Editorial 2010 Calendar

Jan/Feb	Mar/Apr	May/Jun	Jul/Aug	Sep/Oct	Nov/Dec
• Saudi Aramco RTOC • Digitalization • While Drilling Technology • Telemetry • Production • Extended Seismic Feature (4D, OBC, Wide Azimuth)	• Khurais • Near Surface Modelling • Rotary Steerable & Motor Systems • Drill Bits and Underreamers • Complex Wells • Geophysical • Drill-Pipe Integrity	• Manifa • Remote Operation Centres • Drill-Bit Technology • Advances in Drill-Pipe • Zonal Isolation (incl. Packers, Multi-Zone Completions) • Carbonate Reservoir Heterogenity • Exploration Rub Al Khali	• Shaybah • Drilling Optimization • Formation Evaluation • Wellbore Intervention • Casing While Drilling • Multi-Laterals • Tubulars	• Khursaniyah • Passive Seismic • Expandable Completions • Tubulars • Logging and Measurement WD • Environmental Stewardship • Refining	• Hawiyah • Smart Completions • I field • Geosteering • GOSP • OGEP
BONUS CIRCULATION					
	9th Middle East Geoscience Conference & Exhibition 7-10 March 2010 Manama Kingdom of Bahrain **SPE/DGS Annual Technical Symposium & Exhibition** 4-7 April 2010 Seef Centre Khobar, Saudi Arabia	**7th Middle East Refining and Petrochemicals Conference & Exhibition** 23-26 May 2010 Kingdom of Bahrain **72nd EAGE Conference & Exhibition/SPE EUROPEC 2010** 14-17 Jun 2010 Barcelona Spain		**SPE Annual Technical Conference and Exhibition** 20-22 Sept 2010 Florence Italy	**OGEP II Saudi Meeting on Oil and Natural Gas Exploration and Production Technologies** January 2010 **SPE Middle East Health, Safety, Security and Environment Conference & Exhibition** 4-6 October 2010 Manama Kingdom of Bahrain
SPECIAL PUBLICATIONS					
	• Official Magazine	• Official Magazine		Saudi Aramco Supplement	• Official Magazine

Advancing Reservoir Performance

Frac-Point Openhole Fracture Completion System

The one-trip, multistage system for tight gas success

Get to TD quickly and reliably. Accurately fracture multiple intervals in a single trip. Eliminate the need for cementing and perforating operations. Turn marginal unconventional-reservoir prospects into moneymakers.

Choose the Frac-Point™ system if you want a versatile, integrated system that can be optimized for your specific needs, with proven high-performance technology from the world's largest completion toolbox.

And when you choose the Frac-Point system, you get the knowledge and global resources of Baker Hughes, a leader in completion technology.

Meet the challenge of unconventional reservoirs with the Frac-Point system.

www.bakerhughes.com/fracpoint

BAKER HUGHES