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2012 – Issue 24

Saudi Arabia oil & gas

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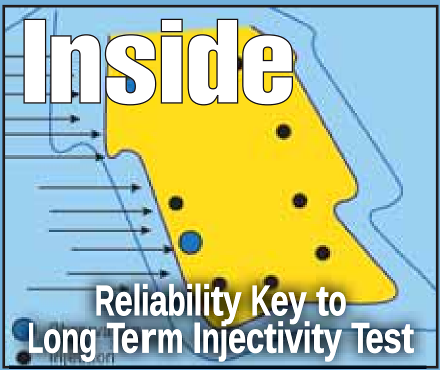

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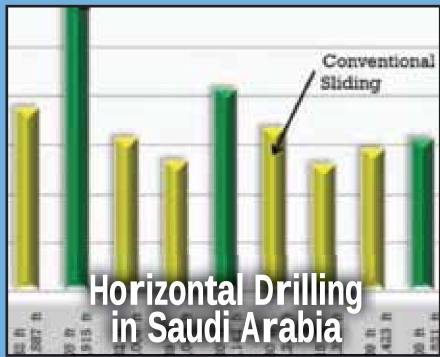

Horizontal Drilling in Saudi Arabia

2011 Saudi Young Professionals Awards

مدينة الملك عبدالعزيز
للعلوم والتقنية KACST

Oil and Gas Research Institute

Hydrocarbon resources (crude oil and gas) are the main source of world energy, and as the international demand increases, the technical challenges increase to meet that demand. Hydrocarbon production optimization at minimum cost and the need to serve the national petroleum industry has been the driving force behind the establishment of the Oil and Gas Research Institute (OGRI) at King Abdulaziz City for Science and Technology (KACST). OGRI is a governmental research and development entity. Its applied research activities concentrate on the upstream sector of the petroleum industry. Fields of interest cover most of the petroleum science and engineering aspects through four main divisions:

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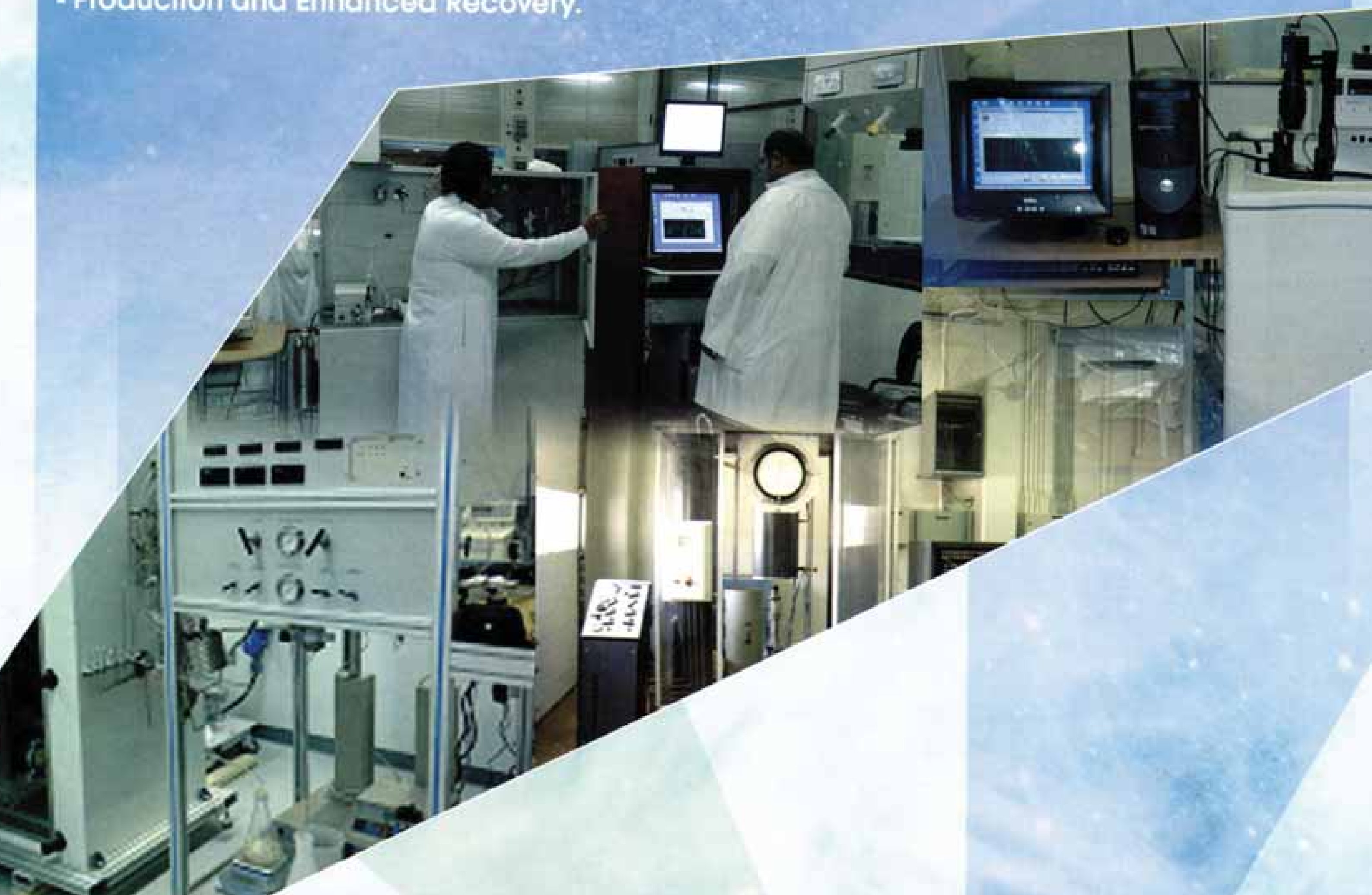

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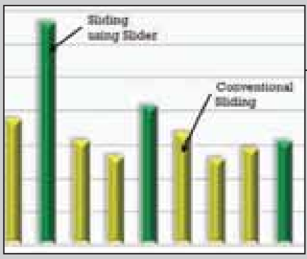

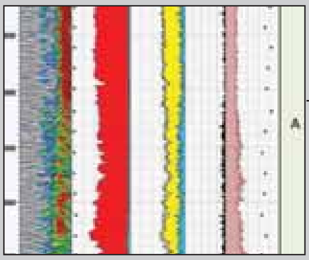

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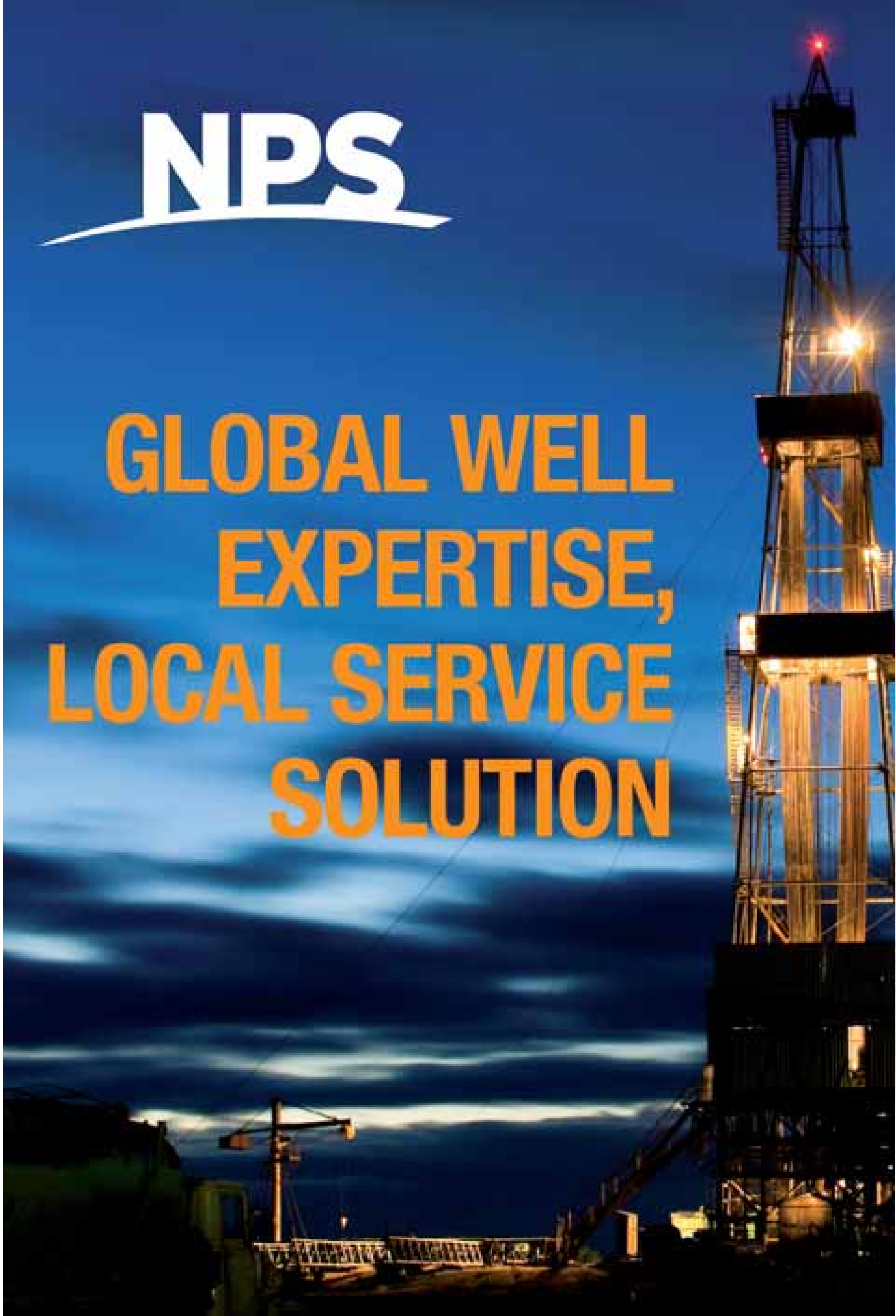

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Investment in Young Workforce

By David Tschanz, Saudi Aramco..

From the mountain villages of the Asir, they come. From the black tents of the Najd and the small cities of the Eastern Province, they come. From the glistening schools of Riyadh and Jiddah and the coastal plain of Jazan, they come. They are the apprentices, and what is in their hearts and minds, and their skills, will shape the future of Saudi Aramco.

Saudi Aramco's industrial workforce – its operators, welders, machinists and electricians, as well as a dozen other occupations – is the heart of its success, said Mohammed Omair, vice president of Refining and NGL Fractionation.

The company's Downstream organization is faced with the one-two punch of an aging workforce – up to 50 percent of Downstream's industrial workforce will change in the next few years – and rapid job growth brought on by changes in technology and company initiatives such as the chemicals business, new refineries and an expanding international presence.

In 2009, Downstream developed a strategy for meeting its need for industrial talent. Currently 3,000 industrial workforce members, including those in Downstream and domestic joint ventures such as SATORP, SADARA and YASREF, are at various stages in their two to three years of training, including apprentices and new trainees.

That number is not expected to drop over the next few years, said Omair. "An active recruitment program has been seeking out and identifying potential candidates from all over the Kingdom," he added.

It is a monumental undertaking and one which provides a major challenge to Downstream's apprenticeship and new employee training programs.

Apprentices undergo a minimum of 18 months of training. They are given 50 hours of safety training, said Richard Weidel, Downstream safety coordinator. "We want them to come on the job knowing how to

> Saudi Aramco's industrial workforce – its operators, welders, machinists and electricians, as well as a dozen other occupations – is the heart of its success.

be safe and treat the equipment safely." If successful in completing training, apprentices are hired into the industrial workforce.

All apprentices go through a detailed on-the-job-training (OJT) program that is based on specific training for a specific plant and piece of equipment, and supported with documented procedures extracted from operating instruction manual. This OJT program is critical to providing young workers with real operation practices to conduct safe operation.

Other training plans include providing Refining and NGLF plant specific simulators for each organization, customized to operate based on specific process flow diagrams. The simulators give users as close to a real experience as can be achieved, and in an area where experience is a significant productivity multiplier. Training simulators allow for hands-on scenario based training that teaches operators how to deal with normal and emergency situations without compromising the actual plant, worker safety or the environment.

"The sheer number of people we'll be training in a relatively short period of time is staggering," said Omair. "Getting it right is going to be one of the great challenges facing the company and our new industrial workforce."

YASREF Joint Venture Signing

Khalid A. Al-Falih, President and CEO, Saudi Aramco, Dhahran, 15 January 2012

"Your Royal Highnesses, Your Excellency Ali Bin Ibrahim Al-Naimi, Excellencies, distinguished guests, ladies and gentlemen: a very good morning to each and every one of you, and for our esteemed visitors from China: zao shang hao. Allow me to begin with a word of welcome to Dhahran, and to the signing of this landmark agreement between Sinopec and Saudi Aramco. I am particularly pleased that we are launching this new venture among so many good friends — and that our signing takes place in the run-up to the auspicious Year of the Dragon in China.

Ladies and gentlemen, it is often said that "practice makes perfect," and if that's true, we and our partners at Sinopec must be getting very good at this, since the Yanbu Aramco Sinopec Refinery Company marks the fourth joint venture between our two enterprises. YASREF, as the former Red Sea Refinery will now be known, takes its rightful place next to our two downstream companies in China's Fujian Province, and our in-Kingdom upstream joint venture, Sino Saudi Gas Limited. In fact, perhaps our most diverse and all-encompassing global relationship is with Sinopec, given that we have upstream and downstream ventures active in both Saudi Arabia and in China – in addition to the provision of oilfield and other services from various subsidiary companies of the Sinopec Group. Sinopec is also our largest crude oil customer, and of course China stands now as the Kingdom's largest crude oil market, making Saudi Arabia the number one petroleum supplier to the People's Republic, accounting for roughly a fifth of total crude oil imports to China.

Judging by this, I would only add that my friend Fu Chengyu and I will keep our pens ready, in anticipation of additional future partnerships which would provide mutual benefits to our two companies, and to the stakeholders we serve here in Saudi Arabia, there in China, and indeed around the globe.

But this latest joint endeavor is simply the most recent chapter in a long history of cooperation, collaboration and trade between Arabia and China. For many centuries, trade routes have linked these two poles of Asia, through an exchange of not only goods, but also of ideas, knowledge and culture – which led to greater prosperity for both of our civilizations.

This newest act of collaboration between our companies and our countries is a significant new element in

> This ultra-modern, highly sophisticated grassroots refinery will process 400-thousand barrels per day of heavy crude oil, and convert every single crude oil molecule into high quality, clean transportation fuels which are in high demand and which meet the most stringent global standards.

the relationship, for YASREF holds enormous potential and promise. It will help to grow the domestic Saudi economy, and create new opportunities for local enterprises and entrepreneurs, including in the initial engineering, procurement and construction phases of the project. This ultra-modern, highly sophisticated grassroots refinery will process 400-thousand barrels per day of heavy crude oil, and convert every single crude oil molecule into high quality, clean transportation fuels which are in high demand and which meet the most stringent global standards. The facility's location in Yanbu', next to two of our other refineries, is ideal for supplying both overseas markets and the fast-growing western region of the Kingdom.

Ladies and gentlemen, let me stress that the various world-class local and international refining and petrochemical investments Saudi Aramco is making is a testament to our firm belief that the downstream remains an attractive and profitable business. In fact, over the next decade our total global refining capacity is expected to approach eight million barrels a day, as a result of the largest expansion today by any oil company in the world.

That's because large petroleum enterprises like us are especially well positioned to maximize long-term value creation from integrated activities encompassing our total value chains, from the wellhead to the gas pump, and to the manufacturing of value-adding fibers, polymers, rubbers and plastics. We are also able to achieve economies of scale, thus furthering competitiveness, as is exhibited by massive projects such as YASREF.

Combine these factors with the additional value which downstream conversion can add to national economies

> "Sinopec also brings to the table not only technical and market know-how and a proud history of achievement, but also a sound understanding of its role as a leader in the global energy landscape."

– including job creation – and one can vividly see the logic of our downstream strategy.

Ladies and gentlemen, Saudi Aramco is in the downstream for the long haul, and Sinopec is one company that shares our bullish outlook. I therefore believe Saudi Aramco and Sinopec should continue to collaborate in this mutually beneficial arena, both in the Kingdom and in the People's Republic.

At the same time, we should recognize that YASREF also stands as testament to the sound climate for foreign direct investment in Saudi Arabia, and as yet another indicator of the attractive business opportunities this nation has to offer strategic investors, such as Sinopec. Saudi Aramco is engaged in a sustained capital program of infrastructure and industrial projects, and in fact the Kingdom as a whole is also pursuing a diverse range of world-scale undertakings in the transportation, utilities, urban construction and industrial sectors. As I have previously shared with our friends in China, I believe Chinese firms have a historic opportunity to invest in the Kingdom and play an important role in implementing those ambitious plans here in Saudi Arabia.

Of course, a project of this magnitude and scope cannot be launched without visionary leadership, and I would like to take this opportunity to thank His Excellency Ali I. Al-Naimi, our Chairman of the Board and the Kingdom's Minister for Petroleum & Mineral Resources who recognized long ago back when he was the CEO of Saudi Aramco, the immense potential of partnering with Sinopec and His Royal Highness Prince Saoud ibn Abdallah, the Chairman of the Royal Commission for Jubail and Yanbu' who facilitated ac-

> "Saudi Aramco is engaged in a sustained capital program of infrastructure and industrial projects, and in fact the Kingdom as a whole is also pursuing a diverse range of world-scale undertakings in the transportation, utilities, urban construction and industrial sectors."

cess to the great infrastructure of the industrial city in Yanbu'; and their respective institutions for their continued encouragement and guidance. I would also like to express my appreciation to all those in the Kingdom and in the People's Republic who worked in support of the creation of this venture.

Finally, let me return to our partner in this venture, Sinopec. In recent years, this world-class firm has gone from strength to strength, strategically expanding its business portfolio and entering new markets around the globe. It has nearly half of China's total refining capacity, and accounts for three-fourths of that nation's crude oil trade. Sinopec also brings to the table not only technical and market know-how and a proud history of achievement, but also a sound understanding of its role as a leader in the global energy landscape. Furthermore, it's commitment to both technological innovation and the communities and economies wherever it operates is evident in Sinopec's establishment of a joint research and development center in the Dhahran Techno Valley.

I am particularly pleased to sign this agreement with Mr. Fu Chengyu, the Chairman of the Sinopec Group, and one of the outstanding leaders in the global pe-

> "... we will have skilled teams at work on this project representing the best and brightest talents from both of our companies, a clearly defined set of objectives in our sights, the firm commitment of the world's best engineering and construction companies, and the continued support of a wide range of Saudi and Chinese institutions."

troleum industry today. Throughout his career, Mr. Fu has exhibited tremendous market savvy, a spirit of entrepreneurship and dynamism, and a deep and abiding commitment to global partnerships as the most effective means of achieving strategic objectives in the energy sphere. Now, at the helm of Sinopec, he brings these traits to our many partnerships, and it is indeed a pleasure and an honor to share the podium and the signing table with him today.

Distinguished guests, ladies and gentlemen: there is a great deal of work ahead of us before we can cap the YASREF initiative with success. Engineering, building and commissioning a refinery of this scale, scope and sophistication isn't easy. But we will have skilled teams at work on this project representing the best and brightest talents from both of our companies, a clearly defined set of objectives in our sights, the firm commitment of the world's best engineering and construction companies, and the continued support of a wide range of Saudi and Chinese institutions. With their collective efforts, I am confident we will implement our plans on schedule, within budget, and to the highest standards of professionalism and excellence. Therefore, I look forward to the day when we meet again in 2014 to formally inaugurate this landmark project, as well as to continued success in our work alongside Sinopec in every area of the business."

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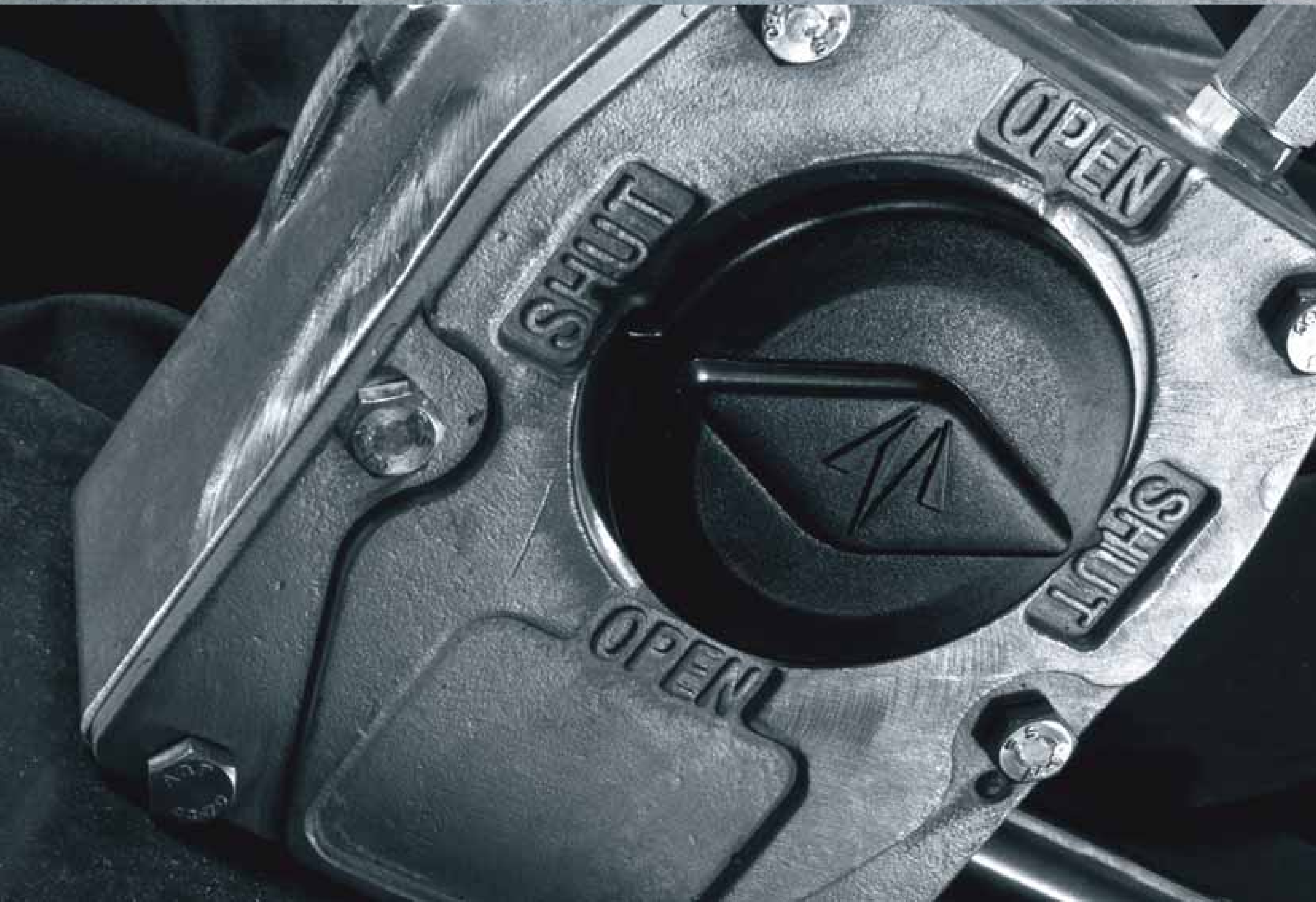

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USC Alumni Club of Arabia; First of its Kind in the Region

By USC Alumni.

First of its kind, the University of Southern California (USC) – Alumni Club of Arabia (ACA) is emerging in the region, starting with the Kingdom of Saudi Arabia. Last September, USC graduates — dating back four decades from many countries — had their fourth gathering in the Kingdom of Bahrain to officially celebrate and inaugurate the successful establishment of the local university affiliated club.

USC enrolls more international students than any other university in the USA. USC- ACA is the 21th club globally and the first to be established in the Middle East and Africa region; one of the largest USC alumni populations outside of California. Established in 1880, it is one of the world's leading private research universities with around 300,000 living alumni dispersed around the world.

Last year's 17th version of the Middle East Oil & Gas Conference and Exhibition (2011 SPE-MEOS) was the platform from which the club held its inaugural celebration. The event was an international reunion with the participation of Professor Iraj Ershaghi, Director of USC's Petroleum Engineering Program and alums of various regional countries.

The idea of creating a local chapter for the university dates back to the late 1970s and was rekindled in a

Group picture of the clubÊs official inauguration celebration onSeptember 27, 2011, in the Kingdom of Bahrain.

> USC- ACA aims to continue providing stimulating, enriching, and exciting alumni activities to keep members connected to USC, lifelong and worldwide.

reunion function for USC alums hosted by the Dean of USC's Viterbi Engineering School, Professor Yannis C. Yortsos, during the 2009 SPE–MEOS event. The need for such an initiative in the region was keenly felt among those wishing to support and connect with fellow alumni and USC. Hence, a core group decided to start in Saudi Arabia and expand thereafter.

The initial gathering, which took place in July 2010, laid the groundwork in assembling the club with the theme "Opportunities for Continued Professional Development and Personal Growth." This reception was organized by Bahjat Zayed, Manager, Southern Area Production Engineering-Saudi Aramco, and sponsored by Mohammad Al-Shammary, at the time President & CEO, Aramco Gulf Operations Company (AGOC) and currently General Manager of Industrial Security Operations at Saudi Aramco. During the meeting, Bahjat Zayed was elected as the first organizing Chairman along with volunteers comprising a core team. A subsequent meeting was held in December 2010 where Al-Shammary presented alumni with an overview of AGOC history and efforts to meet the increased challenges in the upstream energy business.

The culmination of a two year endeavor occurred last September when alumni from across the region attended the inaugural celebration. The event started with Ahmad Al-Kudmani and Karam Al-Yateem delivering welcoming remarks with a historical evolution of the USC-ACA. Zayed proceeded with an opening speech noting that "members are from many disciplines, organizations and countries." He mentioned that with an alumni pool of such a size in the region, the club will proceed to develop programs that meet and address topics of interest to members, provide support to current and prospective students and provide guidance to others interested in establishing similar alumni clubs in the region.

The key note presentation came from Professor Ershaghi, representing the university at the event. He highlighted the recent ranking of the university, its achievements and accomplishments overall and specifi-

Karam Al-Yateem posing with USC President C. L. Max Nikias and USC Dean of Viterbi School of Engineering Professor Yannis Yortsos, during the USC International Leaders symposium in Hong Kong.

cally those of the Viterbi School of Engineering. Many alumni were interested when he shared the school's vision and aspirations under the recently appointed president C.L. Max Nikias.

Zayed presented a token of appreciation to the professor on behalf of USC-ACA. All attendees joined in a cake cutting ceremony, which displayed the USC logo in celebrating the inauguration of the club.

USC- ACA aims to continue providing stimulating, enriching, and exciting alumni activities to keep members connected to USC, lifelong and worldwide. The programs include faculty and alumni presentations, cultural events and career networking forums. For USC alumnus Mazen Dalati Ph.D 1995, "The network should grow as there are hundreds of USC alumni here in the Arab world and in the Middle East."

More recently Karam Al-Yateem represented USC-ACA at USC's International Alumni Leaders Symposium in Hong Kong in October 2011. In this private event for current global alumni club leaders USC-ACA and USC Alumni Club of London were the only two clubs not stationed in Far East Asia. The symposium provides clubs the opportunity to network with, engage and learn from other international clubs. Al-Yateem thanked USC for the invite while highlighting to the audience some of USC-ACA's accomplishments.

On the communication front, From Coast to Coast — the first issue of the club's official newsletter — was distributed during the inauguration event with thoughts written by key individuals from the university — including y Scott Mory, CEO of USC Alumni Association — in addition to various articles.

Group pose in an alumni reception in Denver, from right to left, Bahjat Zayed, Yannis Yortsos, Mohammed Y. Al-Qahtani, Donald Paul, Iraj Ershaghi & Mrs. Ershaghi and Karam Al-Yateem.

Group pose with International Alumni Leaders, in the picture appears, Scott M. Mory, Esq. Associate Senior Vice President and CEO (3rd in the back row from left), USC Alumni Association and Jaimey Wiener Senior Associate Director (3rd in the back row from right), Alumni Clubs and Communities.

Generations of Saudi Aramco USC graduates posing for a memorial group picture, some showing the victory sign – FIGHT ON!

USC-ACA believes that the very existence of such a newsletter will further ease and enhance the way the club communicates with alumni in the region. Copies of this annual newsletter were shared with the USC Office of International Students and the university's Saudi Students Association. The inaugural issue was also distributed at two international events, the 2011 Society of Petroleum Engineers' Annual Technical Conference and Exhibition (ATCE) in Colorado, USA — where an alumni reception was held — and at USC's Annual Global Conference in Hong Kong.

In November 2011, Mohammed Al-Qahtani, VP of Petroleum Engineering & Development at Saudi Aramco, Bahjat Zayed and Karam Al-Yateem attended the annual USC alumni reception at ATCE. Zayed announced the official inauguration of the club that drew the attention of the audience.

The USC Alumni Club organizing Chairman Bahjat Zayed and Core Team members (Ahmad Al-Kudmani, Karam Al-Yateem, Aqeel A. Al-Sadah, and Yasser A. Nughaimshi) are looking forward to utilizing all available resources to nurture and sustain this nascent initiative. If you are a proud USC alumnus or friend looking to get involved with your local alumni chapter, as an active participant or an occasional volunteer, email us at CoreTeam@uscarabia.org.

For additional information, please visit the USC-Alumni Club of Arabia website at http://www.uscarabia.org/

International Imprints for Saudi Young Professionals

By EPRasheed Staff.

2011 Awards recipients posing with 2011 SPE President Alain Labastie; from left to right Carrie Goddard, Hernán Buijs, Abdullatif A. Al-Omair and Faisal N. Al Nughaimish.

In November of last year, Faisal N. Al Nughaimish and Abdullatif A. Al-Omair, Saudi Aramco employees and members of the Saudi Arabia Section of Society of Petroleum Engineers (SPE), were internationally recognized for their services and hours of dedication and commitment in serving the society and its members. They were honored with the Young Member Outstanding Service Award at SPE's Annual Technical Conference and Exhibition (ATCE), held October 31 through November 2, in Denver, Colorado. Considering the fact that SPE serves around 10,000 members in 118 countries worldwide; makes this quite an ex-

2010 Awards recipients posing with 2010 SPE President Behrooz Fattahi. In the picture appear Ashraf Al-Tahini and Christopher Jenkins of Saudi Aramco.

ceptional achievement for Saudi Arabia. Saudi Aramco employees started receiving this award in 2008 and have won it every year since, except for 2009. Statistically 10% of award recipients are from Saudi Aramco. It started with Karam Sami Al-Yateem and HusamAd-Deen S. Madani in 2008 as they were the first from Saudi Aramco, Saudi Arabia, and the Middle East, to receive this international recognition. In 2010, another two Saudi Aramco employees were honored and they are Ashraf Al-Tahini and Christopher Jenkins.

ATCE drew more than 9,000 oil and gas professionals from about 60 countries. Topics included balancing the increased demand for resources with ensuring the highest safety standards. During ATCE, Karam Al-Yateem delivered a presentation to over 400 international young professionals and students titled "the unwritten laws of engineering" and acted as a judge in an international master's level paper contest. AbdulWahab H. Al-Ghamdi's paper, titled "Acid Diversion Using Viscoelastic Surfactants: The Effects of Flow Rate and Initial Permeability Contrast" was rated as the best paper written by a Young Professional in the Well Stimulation discipline. For that achievement, he received a certificate as Winner of the Young Professionals Paper Contest.

The SPE is a not-for-profit professional association whose members are engaged in energy resource development and production. SPE is a key resource for technical knowledge related to the oil and gas exploration and production industry. The SPE's Young Member

Outstanding Service Award recognizes contributions to and leadership in public and community matters, the Society, the petroleum engineering profession, and/or the petroleum industry by SPE members under the age of 36.

Outstanding Service Award recognizes contributions to and leadership in public and community matters, the Society, the petroleum engineering profession, and/or the petroleum industry by SPE members under the age of 36. This award generally recognizes outstanding contributions in the oil and gas industry. The recipients have been nominated by their colleagues and selected by a committee of peers for achievements in their field.

Al Nughaimish's work is known to most members of the SPE Saudi Arabia section through his continuous support for young professionals and students. He has held several positions in the region, the most recent was chairman of the 2010 SPE/DGS Annual Technical Symposium and Exhibition. The event was a first in the Middle East region. He is also a very active member internationally.

Al-Omair leads and assigns full participation in his personal and professional capacity, seeking to promote, maximize and support the full potential of team, company, SPE, and family. His enthusiastic actions have had a positive impact in promoting technical and leadership skills to the increasingly growing number of young professionals in the industry. Al-Omair is a member of the Executive Board of the SPE Saudi Arabia Section and serves as Vice-Chairperson, Technical Symposium.

On a similar note, Msalli Alotaibi, 2011 vice chairman of the Young Professionals and Students Outreach of the Saudi Arabia Section, received the Outstanding

2008 Awards recipients posing with 2008 SPE President Bill Cobb. In the picture appear Karam Sami Al-Yateem and HusamAdDeen S. Madani of Saudi Aramco.

Section Young Professionals Committee Award for the exemplary endeavors and social initiatives the section made during 2011. In addition, the section for the fourth consecutive time received the SPE President's Award for Section Excellence. Another eight members received various awards for their exceptional contributions to the SPE at large. It is worth noting that the Saudi Arabia Section was the first to be established in the Middle East and outside the American continent back in 1959.

In other news, also last year, Yousif Al-Tahan received the regional Young Member Outstanding Service Award, along with other members of the Saudi Arabia Section who received various awards. These winners included: Ramsin Eyvazzadeh, Ali Al-Shahri, Jamal Al-Khonaifer, Nabeel Al-Afaleg and Samantha Jane Horseman.

To Ghaithan A. Al-Muntasheri, SPE Saudi Arabia Section Chairman, who is also a Young Professional, this is not new. "These awards are an outstanding addition to the long lasting history of our section over the 52 year life span of the section."

2011 ATCE Saudi Arabia Section Award & Certification Recipients

Award/Certification	Recipient
2011 President's Awards for Section Excellence and Century Club Award	Abdulaziz A. Al-Ajaji
Distinguished Service Award	Sami A. Al-Neaim
Distinguished Service Award	Sunil L. Kokal
Young Member Outstanding Service Award	Faisal N. Al-Nughaimish
Young Member Outstanding Service Award	Abdullatif A. Al-Omair
Century Club Award and Membership Contest Section Award	Abdulaziz M. Al-Marshad
Century Club Award	Saleh A. Al-Haidary
Century Club Award	Sarah H. Al-Mahroos
2011 SPE YP Paper Contest Winner Certificate	AbdulWahab H. Al-Ghamdi
Outstanding Section YP Committee Award	Msalli A. Al-Otaibi

Reliability Key to Long Term Injectivity Test

ESPs used in non-traditional role help profile production in carbonate oilfield to unlock higher reservoir potential

By Mubarak A Dhufairi, Khalid Al Omairen, Saudi Aramco, and Paul Docherty, Schlumberger.

A complex carbonate oilfield in Saudi Arabia required pressure support to sustain production. Saudi Aramco was looking to achieve sustained production using the best in-class reservoir management practices. The natural drive mechanism came from an aquifer screened from the overlying reservoir by a semi-impermeable tar mat, the geometry of which was relatively unknown, although it was thought to be continuous. Even so, it was suspected that the tar mat might not be completely sealing. Accordingly, any enhanced oil recovery (EOR) plan using traditional water injection would not be effective. This article describes a comprehensive, long-term injectivity test whose objective was to characterize reservoir sweep patterns so the optimum number and location of injectors could be determined.

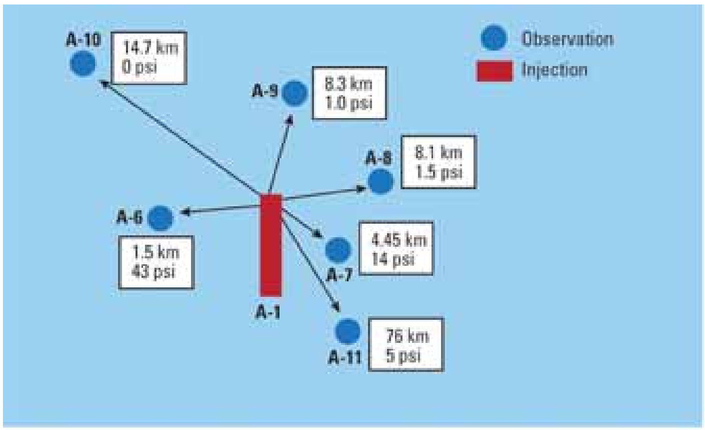
Well placement was critical

The initial approach to avoiding the tar mat issue was to geosteer horizontal injector wells so they landed just above the tar mat, in the transition zone between the heavy and light oil. Geologist and reservoir engineers were faced with the challenge of placing the injectors optimally, so injection water would drive crude oil to the producing wells, leaving no movable oil residuals behind.

Before the entire reservoir pressure support scheme was committed, two pilot tests were designed involving a single injector well and six producers located at varying distances and directions. The six producers were intended to be utilized for observation and to monitor the rate of pressure build up with time for each. The producers/observation wells were equipped with downhole permanent and/or retrievable, high-accuracy, long-lasting, battery-powered electronic gauges. It was decided to perform a long-term injectivity (LTI) test with the objective of mapping the sweep pattern and effectiveness of the injection scheme, in addition to qualifying the injection wells placement strategy. Therefore, to obtain supportable results, a massive test was envisioned involving some 3 million bbl of injected water over a 200-day period. Reliability, resolution and accuracy of the downhole gauges was absolutely essential because it was predicted that changes due to injection water could be quite subtle, particularly on the most remote wells in the observation pattern. At the same time, reliability of the injection setup and equipment was equally important. Any breakdowns could completely mask the data transients the engineers were trying to measure.

Design anticipates tough conditions

With such reservoir conditions, proper placement of injection wells relative to producing wells was of paramount concern to deliver production targets with the highest sweep efficiency model. Robust dual



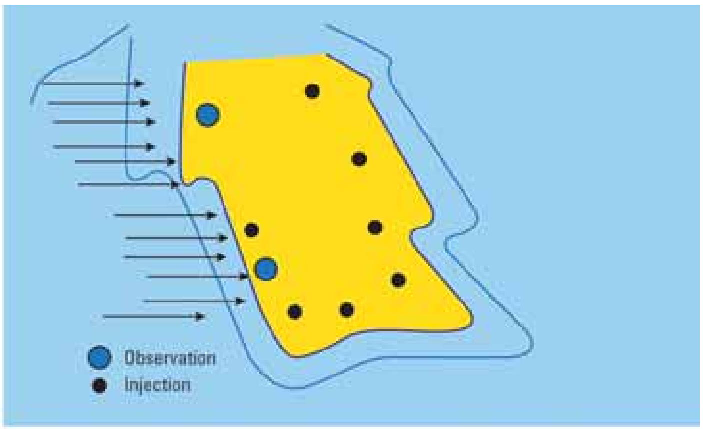


Figure 1: Pilot test well layout includes distance and direction from injection well to observation wells along with observed pressure increase over the test interval. [SOURCE: OTC 21130 Figure 3 with callouts]

memory electronic gauges capable of withstanding sustained high temperatures for at least 31 weeks were specified. The observation wells were equipped with electronic gauges to monitor reservoir pressure response during the LTI test to confirm reservoir lateral connectivity and possible vertical communication between reservoir layers.

In an effort to aid the overall reservoir characterization, the injection well water profile was planned to identify the contributing zones across the horizontal section and map out the crossflow areas. Furthermore, plans were put to record an II/fall off test, which should be analyzed and compared to several pressure transient measurements recorded in several appraisal wells drilled during the project planning period. These measurements served to identify the fluid profiles in those wells along with any anomalies such as crossflow between reservoir levels that might skew pilot test results. The fact that the pilot test was conducted in a dynamic field environment meant that each pressure disturbance had to be accounted for so the final analysis would truly represent the interaction of the pilot test model of a single injector with six observation wells and no outside effects.

A comprehensive test methodology was planned. Pre- and post-injection measurements would be taken that would include both injection and fall-off tests. Thorough transient analyses were planned including:

• Crossplots of differential pressure vs. logarithmic Horner time
• Crossplots of differential pressures and the square root of time
• Crossplots of logarithmic differential pressure and the log of time
• Crossplots of the log of the pressure derivative and the log of time derivative.

Using derivatives is a traditional technique because the derivative is directly represented by one term of the diffusivity equation, the governing equation for models of transient pressure behavior in well test analysis.

Injection wellbore conditioning

A complicating challenge lay in attempting to return injectors to their original status. During drilling, several of the injection wells experienced lost circulation into natural fractures in the carbonate sequences. These were mitigated by pumping viscous pills of hydroxyethylcellulose (HEC) polymers. As a result, many, if not most, permeable zones had high skin damage. To clean up the damage and restore the original skin effect, acid treatments were pumped. To maintain control over the test data, pre- and

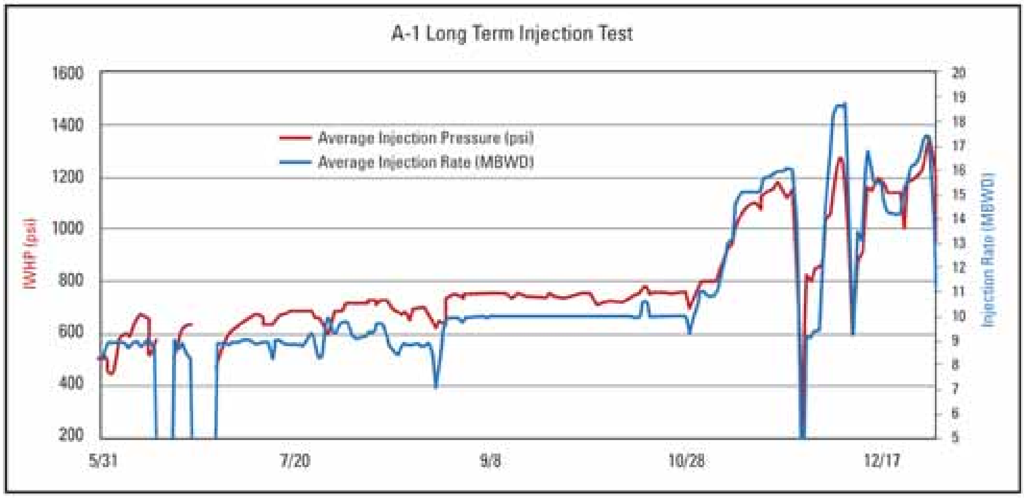


Figure 2: Injection wellhead pressure (red) and injection rate (blue) are plotted as a function of time. [SOURCE: OTC 21130 Figure 4 with callouts]

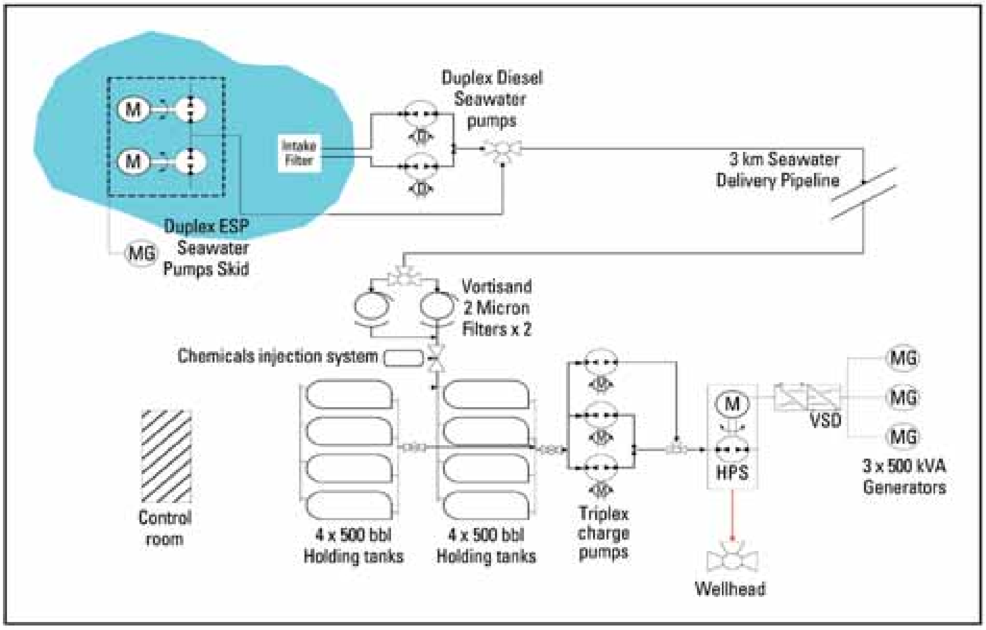


Figure 3: Test schematic illustrates redundancy and integration of reliable ESPs at the seawater intake and at the wellhead HPS [SOURCE: OTC 21130 Figure 1 with callouts]

Figure 4: The use of modular equipment facilitated transportation and setup in the desert and added flexibility to the system design as items were substituted to improve reliability. [SOURCE: OTC 21130 Figure 2]

post-treatment injectivity tests were run. The skin mitigation program was not without its challenges. Deployed into the lateral using coiled tubing pulled by a downhole tractor, the tools became clogged with lost circulation material. A solution was implemented involving bullheading 300 bbl of solvent to dissolve the material that was affecting the control assembly of the tractor.

The post-treatment injection measurements, made using downhole gauges deployed on slickline, consisted of pumping 20,000 bbl of treated seawater into the formations; then pausing to conduct a pressure fall-off test. The fall-off test, which took 96 hours, provided vital information regarding the parameters of the injection scheme. Near-wellbore skin, interwell average reservoir pressure and permeability were determined.

Injection well performance was assessed using Hall-effect plots, based on injection volume and surface injection pressures.

Surface facilities designed for reliability

To avoid further complications, considerable forethought was built-in to the surface system. Basically the plan was to use treated seawater, pumped through a 1.9 mile (3 km) 6-in. diameter pipeline. At the injection well site, two, 2-micron, Vortisand™ sand filters were deployed plus a chemical injection module before the water was pumped into eight, 500 bbl skid-mounted holding tanks. The tanks supplied a set of electrically-powered triplex charge pumps providing input to the horizontal above-ground ESP pumping system (HPS). The pumps were energized using a Schlumberger variable speed drive (VSD) powered by three 500 kVA generator sets.

At the intake, duplex diesel-powered pumps drew seawater from a shallow seaside location. These proved to be unreliable and were replaced by duplex submerged ESPs supplied by a motor generator. To assure the LTI test as a reliable source of injection water, the ESPs were determined to be the best solution. The original diesel pumps were retained onsite as backup. System design capacity was 20,000 bbl/day. At the wellhead, the HPS delivered 10,000 bbl/day of filtered, treated seawater at up to 2,500 psi.

During the design and construction of the surface facility, several important lessons were learned:

- Ensure pump intakes were deep, clean and clear of sand and debris
- Ensure pump not deadheaded into a closed valve
- Address careful alignment of shafts
- Provide a compressor to facilitate system maintenance
- Install tank supports to keep bottom valves accessible
- Use duplex pumps to provide system integrity and backup
- Provide concrete bases for rotating equipment
- Install a subsurface safety valve to block H_2S flow-back from well
- Perform full review of generators and VSDs for compatibility

Injectivity tests reduce uncertainties, save money

The pilot injectivity tests were very successful. Dynamic data, including pressure transient analysis, removed several faults from the geological model. At least 13 injector wells were dropped from the field development plan, largely because uncertainties about the tar mat sealing were redefined. System design issues were successfully resolved to address test goals and result in almost 96% uptime. It was determined that lower powered water injector pumps were required because the injectivity index turned out to be better than expected, and ESPs proved more reliable than diesel-powered pumps. Schlumberger pressure gauge systems and permanent downhole monitors proved both rugged and reliable over the 31-week test period in a hot and highly corrosive environment.

Importantly, data integration with other sources such as drilling data, field production history, available geology and petrophysical analysis from well logs all helped to mitigate risks of skewed interpretation.

*Mark of Schlumberger

Biographies

Mubarak A. Al-Dhufairi is a Production Engineering Supervisor of the Manifa development. His experience includes working on several fields, including Safaniya, Shaybah and Berri fields, along with his experience in drilling engineering. Mubarak received both his B.S. and M.S. degrees in Petroleum Engineering from King Fahd University of Petroleum and Minerals (KFUPM), Dhahran, Saudi Arabia.

Khalid Al-Omairen holds over 25 years of experience in the Oil & Gas industry. His first assignment right after graduation was with Production Engineering for Aindar field in 1986. Later on, he worked as a Foreman and a Superintendent for several offshore and onshore facilities, including Northern Area Oil Operations (NAOO) Well Services Division. Currently, Khalid is the General Supervisor of Safaniya Production Engineering Division overseeing over 2 MMBOD. He has a unique passion to create a work culture attached to continuous simplification of the routine through the adaptation of new technologies and process improvement, a culture that is proactive and flexible enough to accept change and resist returning to old time thinking. Khalid received his B.S. degree in Petroleum Engineering from the University of Louisiana, Lafayette, LA.

Paul R.J. Docherty is an Electrical Engineer. He worked for Shell and Esso as an Electrical Engineer on the FLAGS project upon leaving university, before moving to BP Wytch Farm and joining the ESP Task Force at that location. Paul has some 25 years of experience in ESP Systems, having worked for Schlumberger for 22 years in various capacities. He received his Polytechnic Diploma from Northumbria University, Newcastle, U.K.

Successful Application of New Sliding Technology for Horizontal Drilling in Saudi Arabia

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Abstract

With the focus on continuous drilling optimization, a collaborative effort was implemented to analyze and assess drilling challenges encountered while drilling extended horizontal wells in the Khurais field in Saudi Arabia. The primary goal was to enhance the efficiency of conventional downhole motor systems for directional drilling in the challenging horizontal reservoir section.

Khurais field is located in a remote area in the central part of Saudi Arabia, approximately 200 km from the Saudi capital, Riyadh, and 300 km from the Eastern Province port city of Dammam. The producer wells are drilled in the middle of the field and the water injector wells are drilled close to the field boundaries.

An average of 12 rigs worked simultaneously throughout the duration of the project to drill and complete the required increment wells. The horizontal wells comprise the producers, trilateral producers and power water injectors. The wells are drilled to an average measured depth (MD) of 14,000 ft, with an average of 6,500 ft of open hole section across the reservoir. The 6⅛" horizontal open hole section is particularly challenging. It is drilled with steerable mud motors with the assistance of real time geosteering and logging while drilling tools to maintain the horizontal open hole section of the well close to the top of the reservoir within a window of 3 ft.

The fracture intervals, coupled with high permeability, make the drilling of this section particularly challenging, as mud losses are frequently encountered in this section. The improve the ROP during the sliding process by almost 50% and presents real cases supported by field data. It also underscores the importance of post-action reviews and rig crew training in the achievement of record ROP in the sliding mode. Historical cases are presented, and the benefits of the application of this technology in these wells are explained.

Introduction

An innovative slider system was trial tested in the 6⅛" horizontal section of Khurais' power water injector wells across the reservoir. This section was drilled through the Arab formation, consisting of four members composed of porous layers of carbonates separated by anhydrite. Because special equipment was to be run

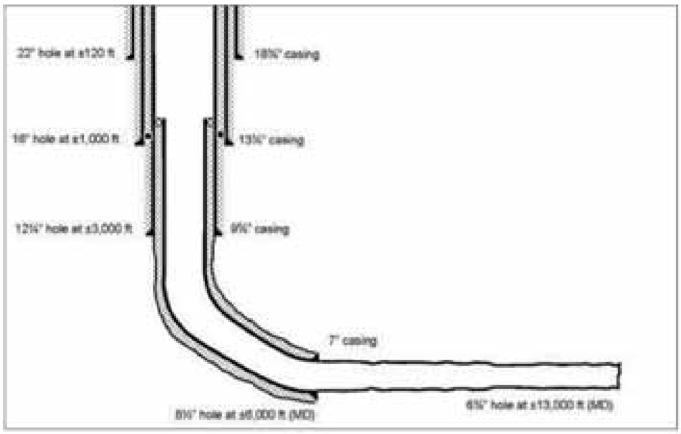

Fig. 1. Design of a typical power water injector well.

across the open hole section, it was very important to drill a smooth well path with minimum tortuosity and to avoid abrupt changes in well direction (high doglegs). The equipment that subsequently was run in this well consisted of an open hole completion with up to six open hole packers and 35 inflow control devices to isolate fractures and improve injection distribution. In addition, acid stimu- lation jobs were conducted with coiled tubing were usually done across this interval. Figure 1 shows a schematic of a typical power water injector well.

This section was drilled with roller cone bits and steerable motors with an outer diameter of 5" and a rotor stator lobe ratio of 6/7 – this configuration represents a low revolution, high torque motor. The motor included a bend at the motor bearing housing at approximately 7 ft from the bit. The distance from the bent housing of the motor to the bit determines the maximum angle change that can be reached. The typical adjustable bent housing angle utilized was 1.5°. In some cases, the required dogleg rate in the horizontal section could reach up to 6°/100 ft; this occurred when adjustments in the well profile were required to maintain the horizontal open hole section of the well close to the top of the reservoir, within a window of 3 ft.

The horizontal sections were drilled using real-time data transmission, geosteering and logging while drilling technology. This collective approach required support from a dedicated team of geologists that was in permanent contact with directional drillers and drilling engineers through a special online platform. The geosteering team requested adjustments to the well trajectory based on real-time logging data transmitted from the rigs.

Directional wells drilled with motors are drilled with drillstring rotation (rotating mode) are not required when corrections in well trajectory, and without drillstring rotation sliding mode) when a change or adjustment to the well trajectory is needed. Conventional drilling in sliding mode is much less efficient than drilling in the rotating mode. In the sliding mode, the motor must be oriented before a slide can begin; orienting the motor involves two steps. First, the drillstring must be oriented in the required direction; it is rotated gradually to place the motor bend in the desired direction. Second, as the bit direction is being established, the torque has to be released from the drillstring so the bit orientation will stay relatively constant. If the torque is not worked out of the drillstring, it may cause the tool face orientation to change as the drillstring is advanced

> To maintain the well trajectory in a window of 3 ft close to the top of the reservoir, a series of rotating and sliding intervals is required, following the instructions of the specialized geosteering center.

for drilling. The bit is initially pointed in a direction clockwise from the
desired drilling direction, thereby counteracting the reactive torque of the motor. This process is often difficult and inefficient to implement[1].

Based on an analysis of approximately 280 horizontal wells drilled with steerable motors in Khurais field, it was found that approximately 30% of the drilling time was spent in the sliding drilling mode. In a sliding mode, hole cleaning is less efficient because there is no pipe rotation and cuttings accumulate on the low side of the hole and produce excessive friction that makes it progressively more difficult for the drillstring to slide smoothly. This friction also makes it difficult to keep a constant weight on the bit (WOB); consequently, the stalling of the steerable motor becomes an issue. Maintaining an acceptable rate of penetration (ROP) while preventing the motor from stalling requires that the motor be operated in a narrow load range. To minimize the problems with maintaining WOB and preventing motor stalling, roller cone bits were used in the Khurais project. Rotary steerable systems (RSSs) with point-the-bit technology were also utilized in the Khurais project. This technology was only used to drill the last part of the extended horizontal sections, when it was difficult to continue drilling with steerable motors due to the high friction that made the sliding process very difficult. The cost of RSS tools is much higher than that of the conventional steerable motors; the new technology presented in this article allows the drilling of higher horizontal displacements with conventional steerable motors, thereby minimizing the overall directional drilling costs.

Brief Description of the Standard Drilling Process

The directional drilling plan for a typical Khurais well requires landing the 7" liner on top of the reservoir at 88°. The 6⅛" horizontal section is drilled to 89° at a 2°/100 ft buildup rate, and the angle is held to total depth (TD) at approximately 14,000 ft measured depth (MD). To maintain the well trajectory in a window of 3 ft close to the top of the reservoir, a series of rotating and sliding intervals is required, following the instructions of the specialized geosteering center. Tool face orientation can shift with changes in WOB and torque; as weight is applied to the bit, torque at the bit increases. Therefore, the overall gross ROP is much less during sliding mode with a steerable motor than during rotating mode. It is not unusual to have the

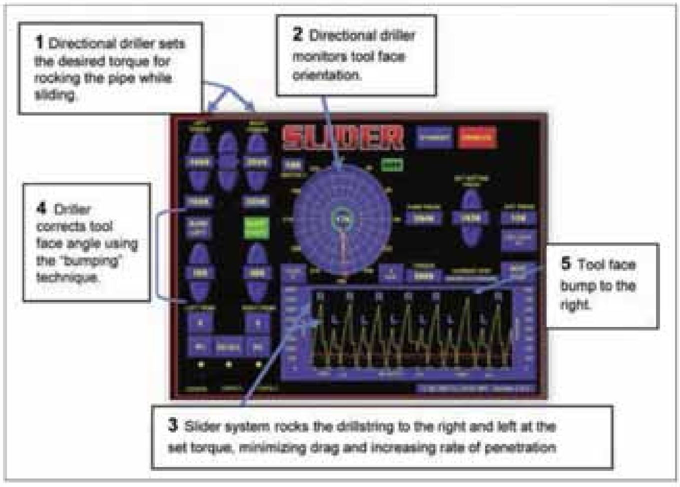

Fig. 2. Illustration of how the new slider technology works.

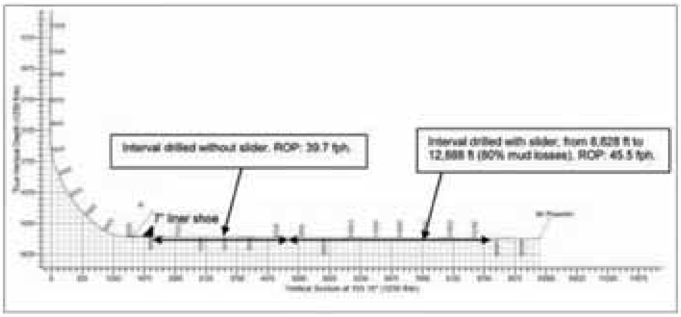

Fig. 3. Interval drilled with slider shows severe mud losses and higher ROP compared to interval drilled without slider.

sliding ROP be as much as 70% less than the rotating ROP2.

To execute a slide, the driller normally stops drilling, picks up the drill bit off the bottom and reciprocates the drillstring to release trapped torque. The downhole motor, with its bent housing approximately 7 ft above the bit, experiences an equal force in the opposite direction (left) of the bit rotation, called reactive torque. To compensate for the effect of the reactive torque on the bit, the driller then must reorient the tool face (clockwise) and control the slack off at the surface to achieve the desired tool face angle. The average clockwise direction compensation required was about 40° in the wells drilled in Khurais field.

Weight is transferred to the bit by slacking off at the surface. The difference between the weight that the bit actually receives and the amount slacked off at the surface is the drag force that opposes pipe movement. Controlling bit weight in the sliding mode is difficult because of the friction (drag) in extended sections, which can cause the WOB to be released suddenly. If a sudden transfer of weight to the bit exceeds what the downhole motor can handle, the motor will stall and the bit rotation will come to a sudden halt. Such stalling conditions can damage the rubber of the steerable motor stator; the amount of damage depends on the amount of the weight transferred to the bit and the number of times the motor stalls. Sudden transfers of weight to the bit are often difficult to prevent[1, 2].

> "The depth to which the point of influence is driven is limited by the fact such that a section of drillstring remains in static friction above the section influenced by the motor torque."

In conventional sliding mode, achieving the proper orientation of the tool face becomes more challenging the more that the horizontal departure increases because of the increased difficulty in eliminating torque from the system during initial reciprocations. Once a proper tool face orientation is achieved, maintaining that orientation also becomes more difficult with increasing horizontal departuresbecause the weight transfer to the bit becomes more erratic, thereby affecting the reactive torque, and consequently changing the tool face angle[1]. The solution to this problem, Fig. 2, describes a sequence of steps to illustrate how the new slider system works.

New Steerable Motor Control System

Saudi Aramco's drilling team and the protect team selected candidate wells for testing the new sliding technology, which consists of a surface control system that interfaces with the top drive control system to overcome many of the friction related problems of steerable motors.

The system works by rotating the top of the drillstring, alternately clockwise and counterclockwise until predetermined surface torque values are achieved; in this way, the upper part of the drillstring always experiences tangential motion. The amount of cyclical torque applied at the surface depends on the particular frictional characteristics of the well. This method keeps drillstring friction in the dynamic mode and significantly reduces axial friction. The amount of cyclical torque applied at the surface depends on the particular frictional characteristics of the well. By sensing the amount of surface torque needed to transfer the proper amount of weight to the bit, and eliminating the need to bring the drillstring off the bottom to make tool face corrections, automated slide drilling allows substantial increases in both the daily footage drilled and the length of horizontal sections that can be achieved[1, 2].

Subsequently, there is no time lost in orienting the tool face, as compared to the conventional method of changing modes. Through manipulation of the surface

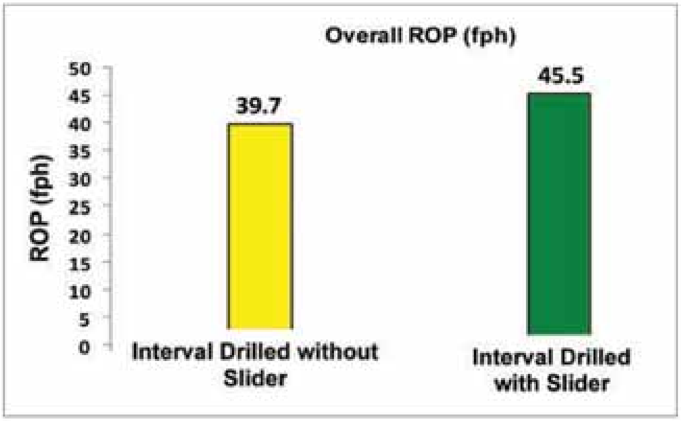

Fig. 4. Comparison of ROP under similar conditions with slider (green bar) and without it.

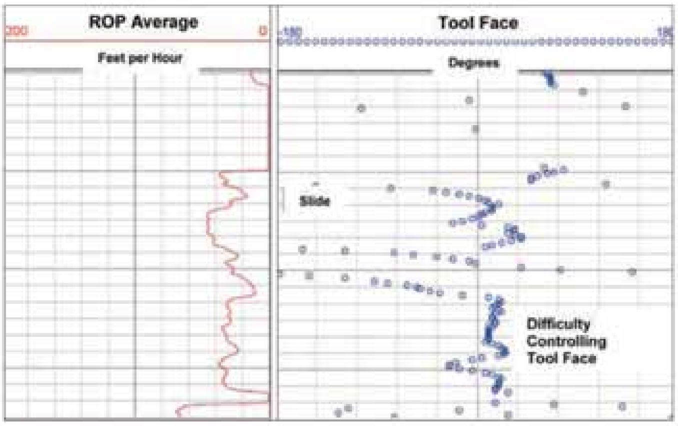

Fig. 5. Section drilled without slider where tool face was difficult to control.

torque oscillations, the driller can move the point of rocking depth as deep along the drillstring as desired. The slider control system uses this principle to improve the performance of drilling with steerable motors. The system drives the point of influence deep enough to significantly reduce the axial friction that causes stick/slipduring sliding.

The depth to which the point of influence is driven is limited by the fact such that a section of drillstring remains in static friction above the section influenced by the motor torque. This static zone provides rotational stability for the motor tool face in much the way that a keel stabilizes a ship. In practice, the optimal oscillating torque applied to the drillstring is determined dynamically at the rig rather than through calculations.

Description

The sliding automation technology consists of software and hardware components. The software component receives three main inputs; information from a manual input screen, surface torque from the top drive and standpipe pressure (as an indication of reactive torque). During the rocking cycle, the system permanently fine-tunes the amount of surface torque applied to the right

> The system adjusts the amount of surface torque needed to transfer the proper amount of weight to the bit and eliminates the need to pick up the drillstring off the bottom of the hole to make tool face corrections.

and left to correct for the change in reactive torque. To orient the tool face during a rocking cycle, the directional driller can change the direction of the tool face by applying toque pulses to the right or to the left. The hardware component is a robotic control system that can be installed in any type of top drive. This surface control system interfaces with the top drive control system and works by rocking the top of the drillstring alternately clockwise and counterclockwise, so the upper part of the drillstring always experiences tangential motion.

Benefits of the Automated Torque Control System

Using the rocking action applied with this system, the drillstring behaves as if it were rotating, and the sliding process is much more effective. The automated slidedrilling allows substantial increases in both the daily footage drilled and the length of a horizontal section that can be drilled with a conventional steerable motor. The system adjusts the amount of surface torque needed to transfer the proper amount of weight to the bit and eliminates the need to pick up the d rillstring off the bottom of the hole to make tool face corrections.

Corrections in the tool face angle are easily achieved through additional torque pulses (bumping) during the rocking cycles. The left-and-right torque rocking initiated by the top drive reduces longitudinal drag in the wellbore, allowing the drillpipe to rotate from the surface down to a point where torque from rotational friction against the side of the hole stops the drillpipe from turning.

To commence slide drilling from the rotary drilling

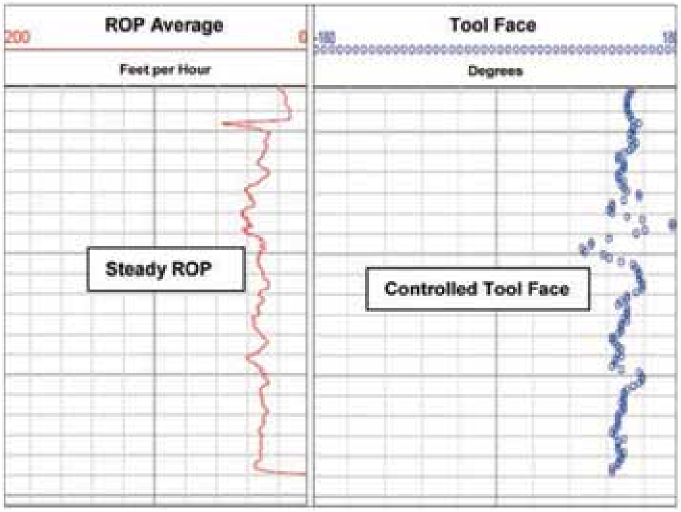

Fig. 6. Section drilled with the slider where tool face was controlled.

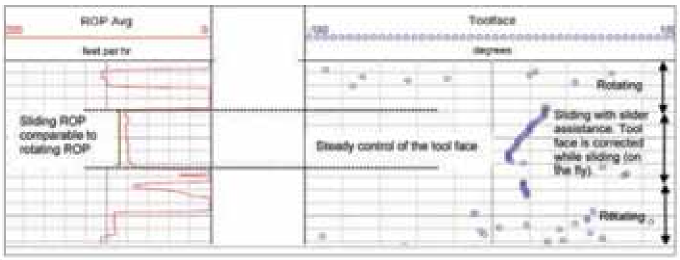

Fig. 7. Sliding ROP using the slider compared to rotating ROP.

mode, the driller simply initiates an automatic rocking action by applying torque to the right and then to the left enough to allow appropriate weight transfer to the bit. The transfer of weight is controlled through automatic adjustments of rocking depth, which compensate for changes in reactive torque[1].

Field Test Results

Figure 3 shows the directional path of a typical well drilled in the Khurais field. The 6⅛" horizontal section had an extension of 8,460 ft from a 7" liner shoe: 5,889 ft to 14,350 ft. The liner shoe was set to an inclination of 85°. The section was drilled with a steerable motor and without slider technology from the liner shoe to 8,828 ft MD. When the well reached 7,000 ft, a severe loss of circulation zones was encountered, and mud returns were only 20%. Under this situation, due to the poor hole cleaning of conventional sliding mode, cuttings began to accumulate in the low side of the lateral. The drilling process continued with water and gel sweeps, but at 8,828 ft MD, the conventional sliding drilling process became extremely difficult due to severe drillstring friction. The operator decided to install the new slider system afterwards to address the excessive friction issue. The slider system was utilized to drill almost 4,000 ft of the horizontal section from 8,828 ft MD to 12,888 ft MD with only 20% mud return. Despite these severe hole conditions, the sliding drilling was carried out successfully.

Figure 4 shows the overall ROP (sliding and rotating) for both sections drilled with the same bottom-hole assembly (BHA) and a similar type of tricone roller bit. The overall ROP in the section where the slider system was used is higher in spite of the additional horizontal departure.

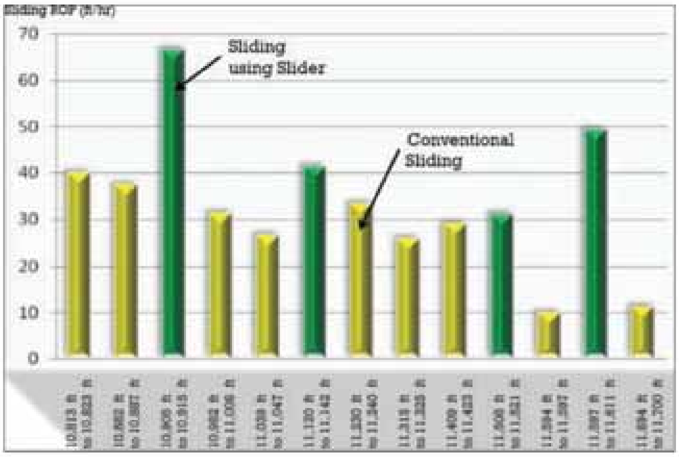

Fig. 8. Sliding ROP in different sections drilled alternately with and without the slider.

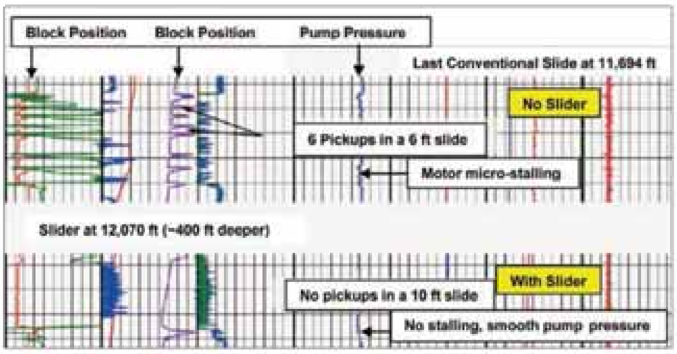

Fig. 9. Comparable performance during sliding drilling without the slider and with it.

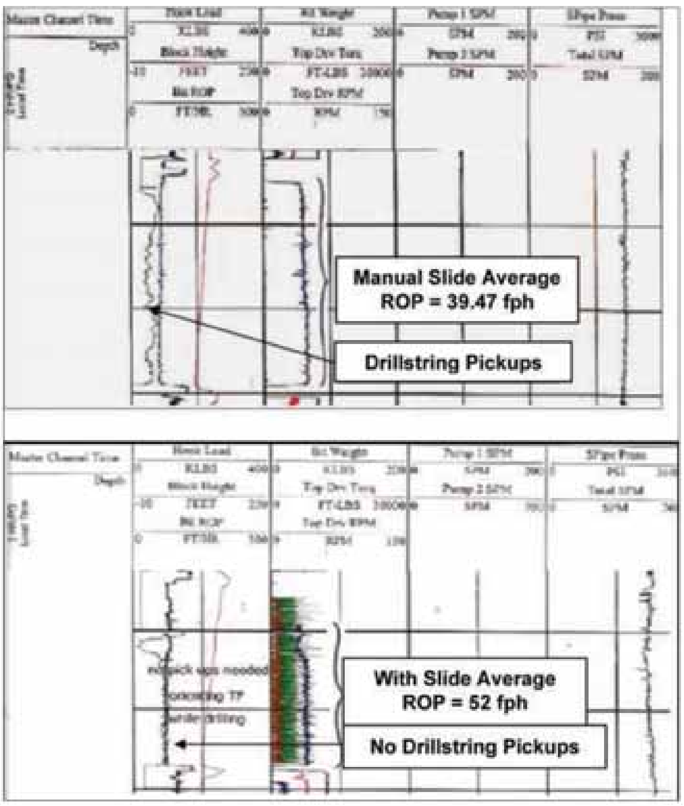

Fig. 10. The top chart shows drillstring pickups during manual slide drilling without the slider. The bottom chart shows that no drillstring pickups were needed when the slider was used.

> "The depth to which the point of influence is driven is limited by the fact such that a section of drillstring remains in static friction above the section influenced by the motor torque."

At 12,888 ft MD, after a vertical departure of almost 8,800 ft, the drilling team decided to utilize a RSS due to the extremely high frictions.

The slider system was also utilized to drill the multilateral Well B. In this well, the 7" liner was set at 7,850 ft with 85° inclination, and the 6⅛" horizontal motherbore section was then drilled to 9,536 ft, where it became very difficult to slide with an acceptable ROP; at that point it was decided to install the slider control system. The drilling continued with the utilization of the slider control system until the TD of the motherbore at 12,070 ft was reached.

A section that was drilled without the assistance of the slider system where the tool face was unsteady and difficult to control due to reactive torque and stalling of the steerable motor is shown in Fig. 5. A plot from a section drilled with the slider, Fig. 6, shows a steadier tool face as a result of the elimination of motor stalling and achievement of smooth WOB due to the slider's rocking action.

Figure 7 shows the ROP while sliding with the slider system vs. the ROP while rotating; both are in a comparable range. If the slider had not been used, the sliding ROP would have been approximately 30% of the rotating ROP. A greater sliding ROP is another benefit of this technology.

From the information tracked in drilling morning reports and on the directional driller parameter sheet, the team determined that the distribution of the drilling time when the slider system wasn't used was 60% sliding and 40% rotating, but with the utilization of the slider system, the ratio changed to 25% sliding and 75% rotating. This reduction in percentage of sliding time is mainly due to the increase in the ROP achieved during sliding mode while using this new technology.

In Well C, the drilling team decided to drill intervals alternately with and without the slider, with the objective of comparing the benefits of this new technology under the same hole conditions and using the same BHA design. The 7" liner was set at 6,200 ft MD and at an

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inclination of 84°; after drilling the 6⅛" section to 7,737 ft, the driller started utilizing the slider system.

Comparable sliding ROPs are shown in Fig. 8. With the use of the slider, the average improvement in the sliding ROP was approximately 60%.

In Fig. 9, a comparison of drilling parameters (block position and pump pressure) in two sections drilled in sliding mode with and without the slider is shown. The top chart shows motor stalling and drillstring pickups due to inefficient transfer of weight to the bit, the bottom chart shows that with the assistance of the slider system, no drillstring pickup was required and no pump pressure spikes were experienced.

In Well D, the slider was used to drill the whole horizontal interval from 6,200 ft MD to 11,213 ft MD. At 9,500 ft, the drag reached 45,000 lbs, but rocking the drillstring with the slider was effective in overcoming the friction and minimizing pipe buckling to effectively transfer weight to the bit.

Figure 10 shows two charts. The top chart represents the manual sliding section, showing the drillstring pickups required to orient the tool face, and the bottom chart shows that drillstring pickups were not necessary when the slider was used.

Conclusions

This new technology proved that it is possible to overcome the friction related problems of steerable motors by rotating the drillstring alternately clockwise and counterclockwise, so the upper part of the drillstring always experiences tangential motion. This technology allows the transfer of weight smoothly to the bit, thereby eliminating motor stall. The sliding ROP was

> "The slider system ensured a very steady tool face and showed an excellent capability to correct the tool face angle whenever required, and it provides a means to correct the tool face orientation while sliding."

increased by 70% in some cases. The slider system ensured a very steady tool face and showed an excellent capability to correct the tool face angle whenever required, and it provides a means to correct the tool face orientation while sliding.

The success of the slider depends on the proper training of the directional drillers and ensuring they use it in the way it was designed to be used. The training usually takes 3½ hours, and it is recommended that training occur away from the rig. Nothing goes downhole, so there are virtually no failures.

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Utilizing NMR and Formation Pressure Testing While Drilling to Place Water Injectors Optimally in a Field in Saudi Arabia

By Dr. Dhafer A. Al-Shehri, Mohammed S. Kanfar, Yusuf Al-Ansari and Syed Abu Faizal.

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Abstract

Detecting the presence of tar, or heavy oil that does not flow, using conventional production technologies presents numerous challenges in field development. Tar, acting as a permeability barrier, will often break flow and pressure communication from the aquifer to the oil zone. This results in inadequate water pressure support, which is necessary for sustaining production levels that maximize oil recovery. One of the key issues in developing a field with known tar mat accumulation is how to optimally place the injectors away from the tar. The problem becomes more complicated when the exact location of the tar mat is uncertain, either laterally or vertically. Tar mats are usually neither flat nor uniformly thick across a field. These uncertainties pose a challenge in planning wells, especially water injectors.

Detection of tar is critical for reservoir characterization, reserves calculation and well placement. Direct and indirect techniques are employed to detect tar, including core analysis, well testing, wireline logging and the Pyrolitic Oil Productivity Index (POPI). These produce measurements that are good indicators of tar; however, the challenge is to identify the tar while drilling the well. Early detection requires the deployment of logging while drilling (LWD) technology for real-time interpretation of data.

To accurately identify tar in reservoir sections in real-time, the integration of conventional logging while drilling (LWD) measurements with new technologies, such as the slim hole nuclear magnetic resonance (NMR) and formation pressure while drilling (FPWD), is necessary. This allows for timely adjustments to the well path and prevents costly remedial actions.

This article discusses successful real-time applications of slim hole NMR and FPWD technologies to detect tar and optimally place water injectors. This is further demonstrated with a discussion of two case studies involving extended reach power water injectors.

Introduction

Many reservoirs in the Middle East are characterized by layers of heavy immobile oil, also referred to as tar mats, which create additional challenges to pressure support and recovery strategies. Tar mats are present in numerous Middle East reservoirs, including those

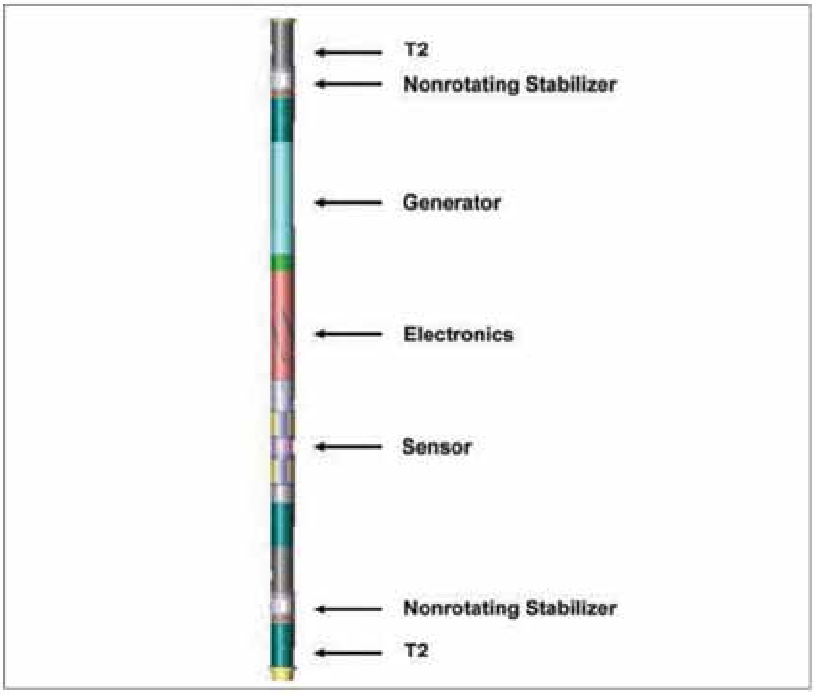

Fig. 1. A 4$^{3}/_{4}$‰ NMR LWD tool assembly for 5$^{7}/_{8}$‰ and 6$^{1}/_{8}$‰ hole applications.

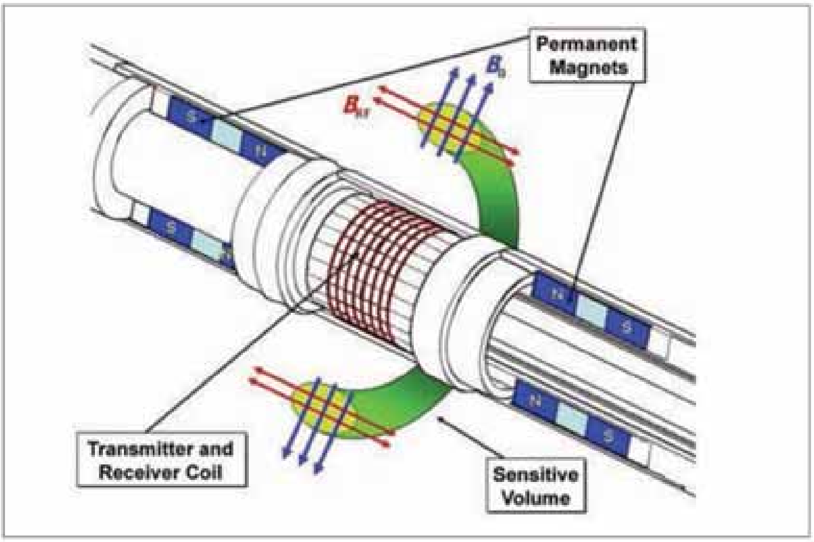

Fig. 2. NMR LWD sensor sub arrangements.

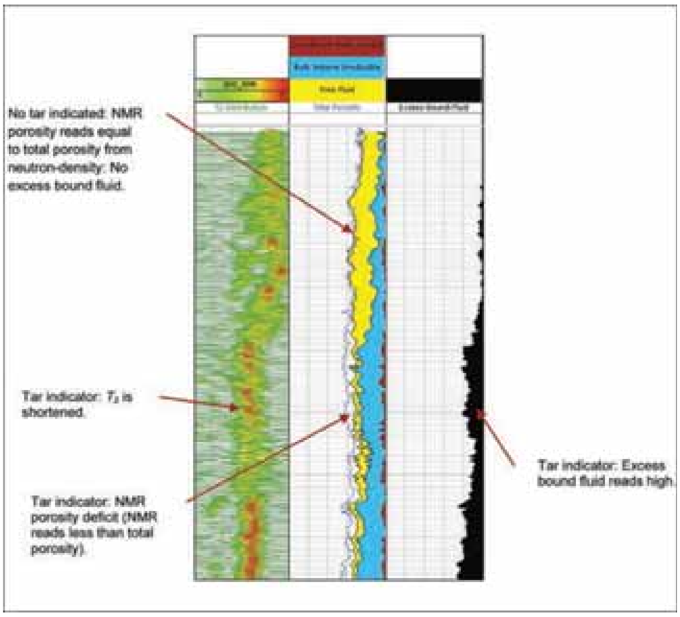

Fig. 3. Tar indication and characterization from NMR by porosity deficit, excess bound fluid and T_2 distribution shift.

in Iraq, Kuwait, Qatar, Oman, Abu Dhabi and Saudi Arabia[1]. The tar mats in these reservoirs are highly viscous, immobile accumulations found between an underlyingaquifer and the lighter oil above. One of the main tar issues in such reservoirs is that it acts like a barrier between the oil zone and the aquifer, impeding the natural bottom water drive and rendering water injection into the aquifer for pressure maintenance ineffective. The complexity of reservoir management in these types of reservoirs is increased by the uncertainty of the lateral and vertical extent of the tar mats throughout the field.

One of the most effective strategies in developing these fields is placing of the horizontal injectors as deep as possible in the oil zone, just above the tar mat. The uncertainties related to the tar make it extremely important to identify it early; then required adjustments to well plans can then be made accordingly. Integrated workflows, including conventional logs, nuclear magnetic resonance (NMR), formation pressure while drilling (FPWD) and other tar indicators, have been effectively employed to drill long horizontal wells in carbonate reservoirs characterized with tar accumulations.

Tar Identifying Technologies

Nuclear Magnetic Resonance While Drilling Figures 1 and 2 are schematics of the NMR logging while drilling (LWD) tool and the sensor sub arrangement, respectively. The sensor sub consists of two arrays of permanent magnets that generate a static magnetic field, while the coil antenna generates the radio frequency. The permanent magnets in the tool polarize the formation near the wellbore, forcing the hydrogen nuclei in the pore fluid to align with the direction of the magnetic field. The formation is then subjected to a sequence of radio frequency pulses perpendicular to the magnetic field. This causes the hydrogen nuclei to reorient repeatedly, which produces a characteristic de-

> "Many applications for FPWD have been found over the years, including estimating near wellbore mobility, reservoir connectivity assessment and equivalent circulating density (ECD) management."

caying signal. Evaluation of the amplitude and decay rate of the signal yields information about the field's porosity, the fluid content and the rock.

NMR directly measures fluid-filled porosity and allows differentiation between movable and bound fluids. The main advantage of NMR porosity measurements over porosity measured with other logging tools is that the NMR porosity is independent of lithology. The NMR measurement also does not need radioactive sources, which is the most obvious safety advantage over other nuclear methods. From a petrophysical point of view, the NMR measurement delivers much more information about the formation than porosity only. This includes:

•Partial porosities: Clay bound water, irreducible bulk volume and movable bulk volume.
•T_2 relaxation time distribution vs. pore size distribution.
•Permeability index.
•Hydrocarbon typing.
•Hydrocarbon saturation.

NMR plays an important role in identifying tar or low permeable zones. In tar, the NMR total porosity can show a deficit compared to the total porosity determined from conventional logs, such as density and neutron, Fig. 3. This is due to the fact that the decay times of the portion of the NMR signal measuring the solid hydrocarbon phase are too fast to be detected by the logging tool. Another good tar indicator, known as excess bound fluid, is the difference in the bound fluid porosity from the NMR log and the bulk volume of water from the conventional logs. When tar is present, the excess bound fluid volume is a positive value. De-

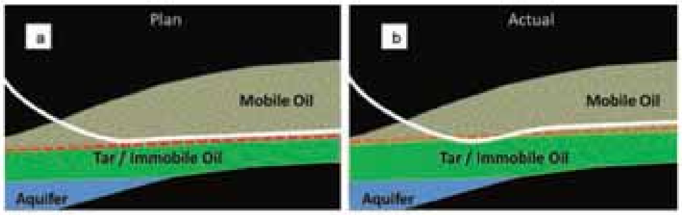

Fig. 4a. Planned well path for Well-X.
Fig. 4b. Actual well path for Well-X after adjusting in real-time for tar.

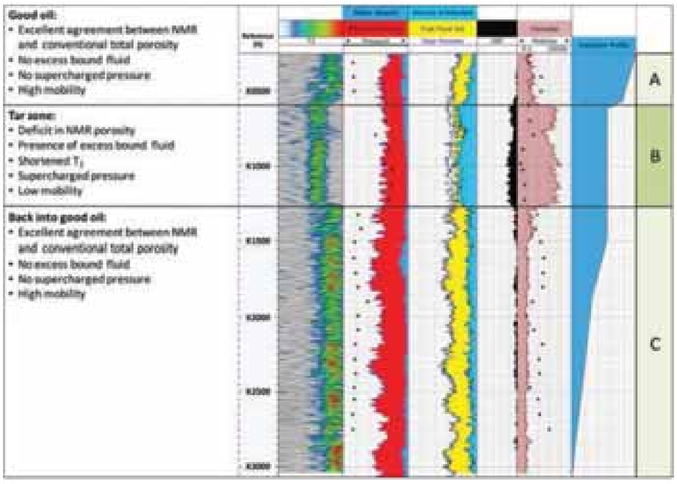

Fig. 5. Well-X LWD logs from NMR, FPWD and triple combo tools.

tailed explanations of this concept can be found in other sources[2].

Furthermore, reservoir fluid viscosity can also be determined using NMR measurements, given that higher viscosity fluids show up at shorter T_2 times[3, 4].

Formation Pressure While Drilling

FPWD was introduced to accurately measure formation pore pressure in real-time. Many applications for FPWD have been found over the years, including estimating near wellbore mobility, reservoir connectivity assessment and equivalent circulating density (ECD) management.

FPWD operates during a brief stoppage in drilling; the tool pushes a pad sealing element against the wellbore wall and performs a series of pressure drawdown and buildup tests to measure formation pressure. The measurements are performed relatively quickly to minimize the chance of differential sticking, especially in long horizontal wells.

Recently, FPWD has been used successfully in combination with LWD NMR in detecting heavy/immobile fluids. In clean carbonates, zones containing immobile, highly viscous fluids are generally characterized by lost seals, supercharged pressures and very low mobilities in the range of 0.1 millidarcies/centipoises (md/cp) to

> Unlike other logging tools, the POPI provides a direct assessment of residual hydrocarbons on rock samples, which can be used to assess the oil's connectivity with the active fluid system in the reservoir.

0.2 md/cp[5]. Real-time detection of zones with immobile fluids and low permeability allows drillers to avoid them and makes geosteering long horizontal wells into sweet spots possible.

Pyrolytic Oil Productivity Index

The POPI was developed by Saudi Aramco to provide a quantitative assessment of reservoir quality, productivity, water saturation and tar identification from residual hydrocarbon staining on drill cuttings. Unlike other logging tools, the POPI provides a direct assessment of residual hydrocarbons on rock samples, which can be used to assess the oil's connectivity with the active fluid system in the reservoir.

The POPI employs various pyrolysis methods, such as the assessment of API gravity, the apparent saturation method, and the volume organic matter method. The POPI can accurately quantify tar volume over a wide range of concentrations to support real-time application and geosteering of horizontal wells[6].

Integrating Tar Identifying Technologies

Two case studies from a Saudi Arabian field demonstrate the successful integration of tar identifying technologies. Both cases involve long horizontal water injectors drilled in oil bearing clean carbonate formations. The knowledge of the tar zone depth gained from the first well was thoroughly utilized in drilling the second well. In both cases, different tar identifying technologies were effectively used to properly geosteer the wells and achieve the production objectives.

Case 1

Well-X is a water injector that in real-time was successfully placed away from the tar in a clean carbonate reservoir that is both heterogeneous and characterized by an undulating tar mat. Based on the best tar depth

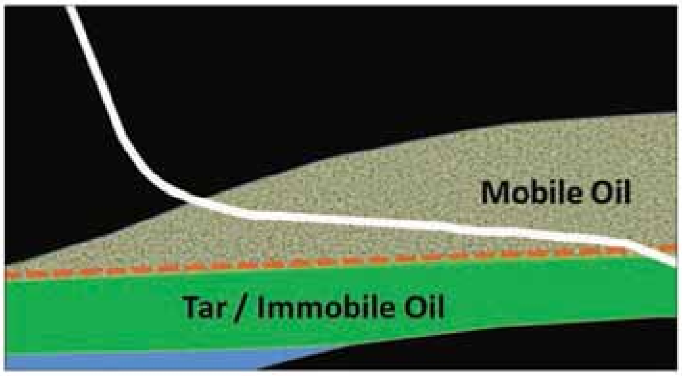

Fig. 6. Proposed well path for Well-Y.

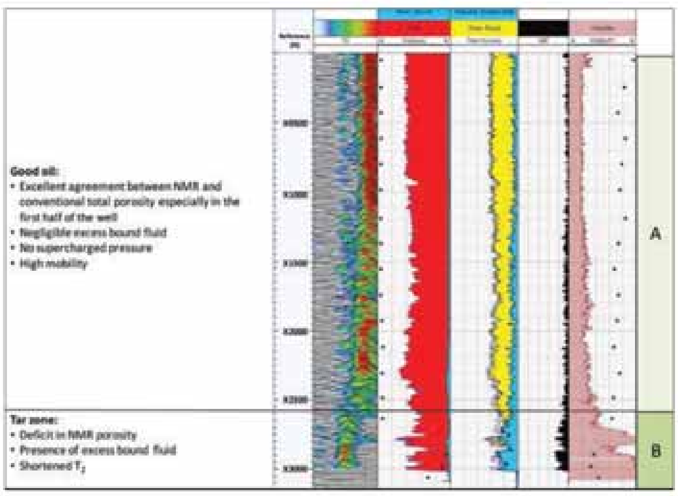

Fig. 7. Well-Y LWD logs from NMR, FPWD and triple combo tools.

estimations from nearby offset wells, the original plan of Well-X was to enter the reservoir as deep as possible in the low viscosity oil zone, but to avoid the tar just below it. Figures 4a and 4b show the planned as well as the actual well paths.

The challenge was to drill a long horizontal section just above the tar without entering it. The light oil-tar contact was very uncertain. The drilling bottom-hole assembly (BHA) was equipped with tar indicating technologies, such as LWD NMR, FPWD and a surface POPI unit to analyze real-time the drill cuttings. T_2 distribution, NMR derived porosities (free fluids and immovable fluid volumes), formation pressures and mobilities were transmitted real-time along with the conventional logs like gamma ray, density and neutron porosity, to identify tar and make quick decisions to change the well plan if necessary. Along with the conventional curves, viscosity from NMR measurements and excess bound fluid were also calculated and displayed.

As planned, the well entered the low viscosity zone (Zone A) of the reservoir, Fig. 5. A couple of hundred

> The benefits of these technologies were made clear by a short-term injectivity test conducted after the well was completed, which showed poor injectivity in the identified tar zone (Zone B), but a very goodinjection rate in the low viscosity oil zone (Zone C).

feet into the reservoir, the formation pressure tests were performed and showed pressures indicating super-charged (Track 3) and very low mobility values (Track 6). The tails of the NMR T_2 distribution (Track 2) also showed a shift towards the left (towards faster relaxation times). These were the first indications of tar, though the shape and position of the T_2 distributions are not a unique tar indicator and can be affected by other factors (pore size reduction, wettability alteration, etc.) as well.

Track 4 of Fig. 5 compares the total porosity derived from neutron-density logs (blue curve) with free and bound fluid porosities from NMR (shaded in yellow and blue), respectively. There is very good agreement between total porosity and NMR porosity in Zones A and C; however, in Zone B, once the T_2 distribution shifts towards faster relaxation times, the NMR shows a porosity deficit compared to total porosity, and the computed viscosity indicates highly viscous tar. Another clear tar indication comes from the excess bound fluid, which is shown in Track 5 as a black-filled curve.

These indications proved to be very useful in making decisions in real-time. The well plan was revised to navigate the well out of the tar zone. Once the depth of the tar zone was identified, the rest of the well section was maintained above it, which is clearly indicated by the data from Zone C, Fig. 5. The benefits of these

"Based on the knowledge gained from Well-X concerning the tar depth, another water injector well, Well-Y, was planned, also to be drilled and placed above the tar in the low viscosity oil zone."

technologies were made clear by a short-term injectivity test conducted after the well was completed, which showed poor injectivity in the identified tar zone (Zone B), but a very good injection rate in the low viscosity oil zone (Zone C).

Case 2

Based on the knowledge gained from Well-X concerning the tar depth, another water injector well, Well-Y, was planned, also to be drilled and placed above the tar in the low viscosity oil zone. This time it was decided to drop the angle of the well towards the end in an attempt to confirm the presence of tar just below. Figure 6 shows the proposed well path for Well-Y.

The same BHA, employing the tar detection technology, used in Well-X was utilized in this case as well. As per the plan, the well entered the low viscosity zone (Zone A) of the reservoir, Fig. 7, which is indicated by high mobilities from FPWD (Track 6), late peaks in the NMR T_2 distribution (Track 2) and the total porosity from neutron-density logs overlying the NMR derived porosity (Track 4).

The well angle was held for a few thousand feet to stay at the same true vertical depth, then just prior to reaching 300 ft from the total depth, the well was deviated downwards. As the well entered into deeper zones, the NMR T_2 distribution shifted towards the left, a deficit in NMR porosity was indicated, and excess bound fluid showed an increase.

Therefore, all indicators confirmed the presence of tar.

Conclusions

The case studies prove the effectiveness of integrating NMR, FPWD and POPI technologies in real-time for identifying tar zones in clean carbonate reservoirs.

> "The well angle was held for a few thousand feet to stay at the same true vertical depth, then just prior to reaching 300 ft from the total depth, the well was deviated downwards."

1. In the first case study, the tar zone depth was successfully established with the help of tar identifying technologies in a long horizontal injector. It was confirmed by a short-term injectivity test, which showed extremely low injectivity in the identified tar zone.

2. The second case study shows the effective use of the tar depth knowledge from the previous well to drill a new long horizontal injector deep into the low viscosity zone without entering the tar. The depth of the oil-tar contact was confirmed by tar identifying technologies when the well dipped into the anticipated tar zone.

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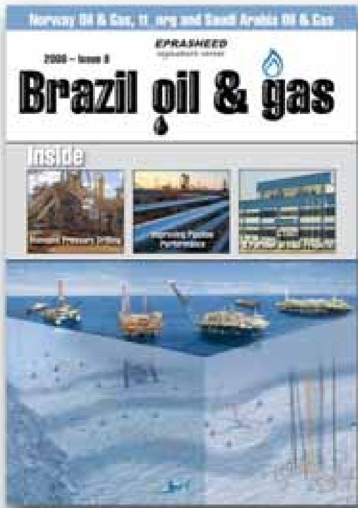
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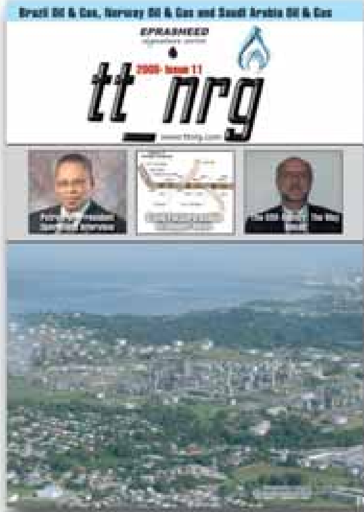
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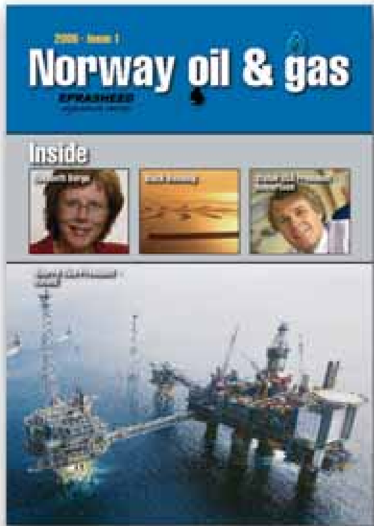
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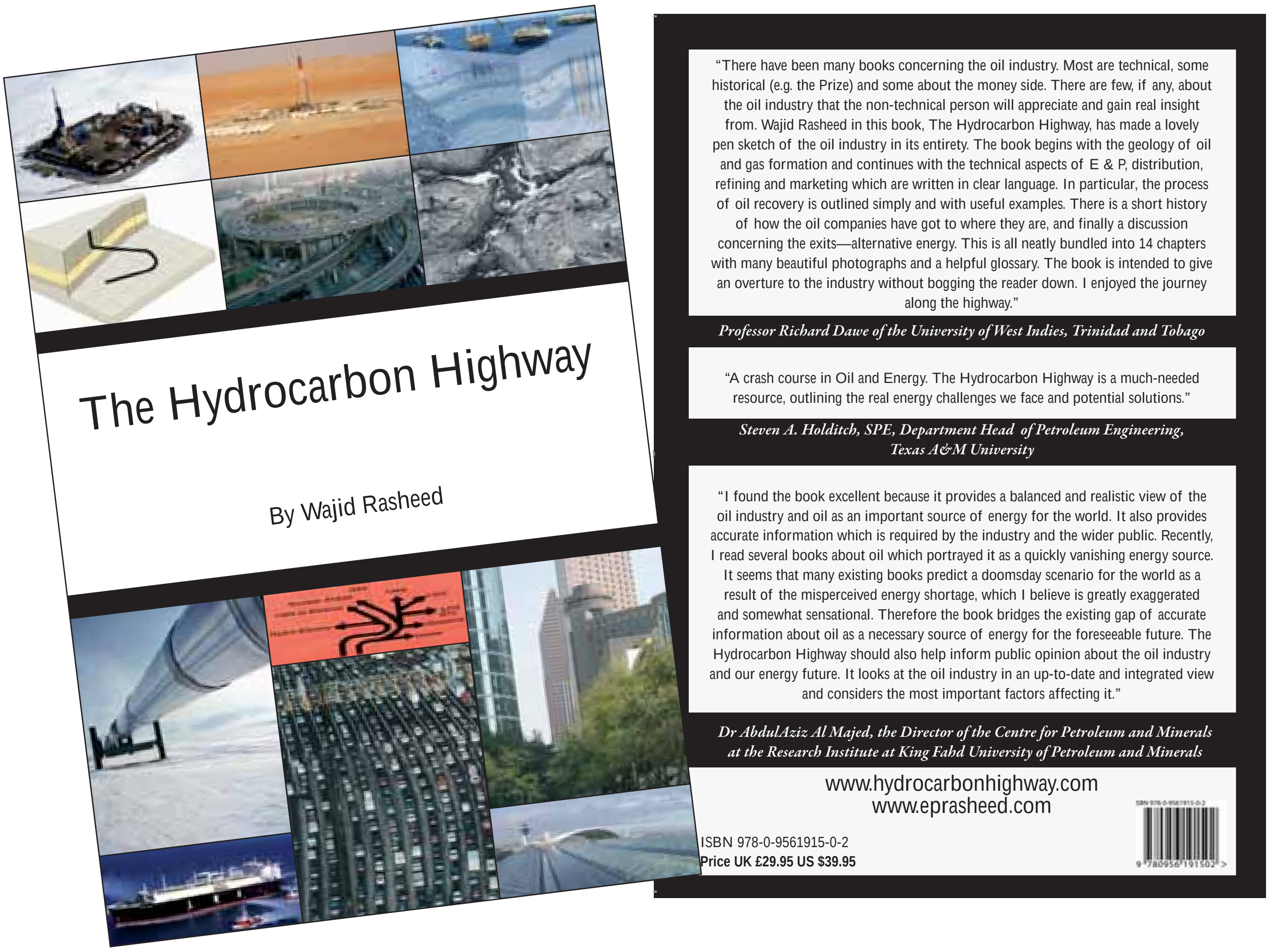
Inside

Reserves, Peak Oil and Medieval Maps



Are we running out of oil? Before we can answer that question, we need to understand what oil and gas reserves are and how they are measured.

Reserves are very significant numbers. They form the base of a slew of Key Performance Indicators (KPI) for all types of oil companies. Yet, the lack of a globally accepted standard makes the measurement and auditing of reserves a thorny issue. An integrated understanding of worldwide reserves is also lacking. In this chapter, we consider reserves measurement systems, global reserves and 'peak oil'. One key question interests us: are

> "Beyond annual profit concerns, the long-term survivability of the oil company is wholly dependent on the rate at which production and reserves are increased."

we navigating through global reserves using a 'medieval' and outdated map? If so, is peak oil a physical or psychological shortage?

Invariably, reserves grab headlines due to their financial significance, measurement methods or the geo-political dimension. On the one hand, the sustainability of oil companies depends on reserves and, on the other, oil company profits depend primarily on production. By breaking down reserves and production data, analysts can derive KPIs such as net worth, reserves to production ratio, reserves replacement and production quotas and positive cash-flow. Consequently, reserves and production are inextricably linked to financial performance.

Major, National and Private

Existing irrespective of oil company size or shareholding, the link between reserves and financial performance is a fundamental one. Majors, public or 'floated' companies, will be judged by analysts on their short-term earnings and long-term prospects. Private companies will be judged by shareholders on Return on Investment (ROI). National or state companies are subject to analysis too which we will consider short-ly. The stock prices of oil companies are heavily influenced by their stock-in-trade – oil. The oil company itself will use KPIs such as production rates and reserves replacement to make financial valuations and earnings projections. Financial analysts ultimately look to these figures and make 'buy, sell or hold' recommendations.

Reserves, therefore are a major influence on the stock price of major International Oil Companies (IOCs). Of course, IOC stock prices will be affected by quarterly profits and shareholder dividends. The oil price and other contextual factors that affect the attractiveness of the industry as a whole for investment – geopolitics, speculation and 'futures' trading – will also affect stock ratings. Beyond annual profit concerns, the long-term survivability of the oil company is wholly dependent on the rate at which production and reserves are increased. Usually this happens in one of three ways: first, through the 'drip-feed' of incremental recovery using mature field improved technology; second, by boosting reserves through the bit which means that successful

> "It would be physically impossible to accurately measure oil and gas in place; therefore, the industry relies on extrapolated measurements as accurate measurements can only occur upon production."

wildcat strikes open new frontiers; and finally, by the acquisition of another oil company through its stock[1].

National Oil Companies

There is a common yet incorrect perception that National Oil Companies (NOC) are somewhat immune from scrutiny of financial indicators; however, there are at least two scenarios where NOCs will be judged by analysts. This primarily occurs when financial experts assess financial risk and assign credit ratings to NOCs and their countries of origin. In major oil exporters, i.e. exporting more than 2 million barrels of oil per day (MMbbl/d), the NOC is often the largest business in the country*. Country risk can therefore be considered a function of the NOC's performance. This has a direct bearing on the credit rating of countries. A secondary situation occurs when analysts assess the attractiveness of financial instruments or debt (bonds), issued by the oil company or government, based on ROI and risk.

Certain NOCs, such as those within the Organisation of Petroleum Exporting Countries (OPEC), also depend on reserves in another way. OPEC production quotas are allocated as a proportion of total proved reserves. Consequently, countries with high reserves volumes are given higher thresholds of production[2,3].

Uncertainty

Measuring reserves is difficult and involves a basic uncertainty because reserves lie hidden away in deep subterranean reservoirs. It would be physically impossible to accurately measure oil and gas in place; therefore, the industry relies on extrapolated measurements as accurate measurements can only occur upon production. Consequently, measuring, corroborating and auditing the measurement of reserves is an inexact science.

To make matters more complex, there is no single standard or methodology that is universally accepted by the industry or by the financial community, i.e. regulators/analysts. Substantive variations exist between institutions and nations. Exemplifying this are differences between the SPE (Society of Petroleum Engineers) and SEC (Securities Exchange Commission) criteria for reserves classification, and international variations between the Russian and Norwegian systems[4,5].

Figure 1 - The Total Size of the Oil Resource is 3.012 Trillion Barrels (EPRasheed)

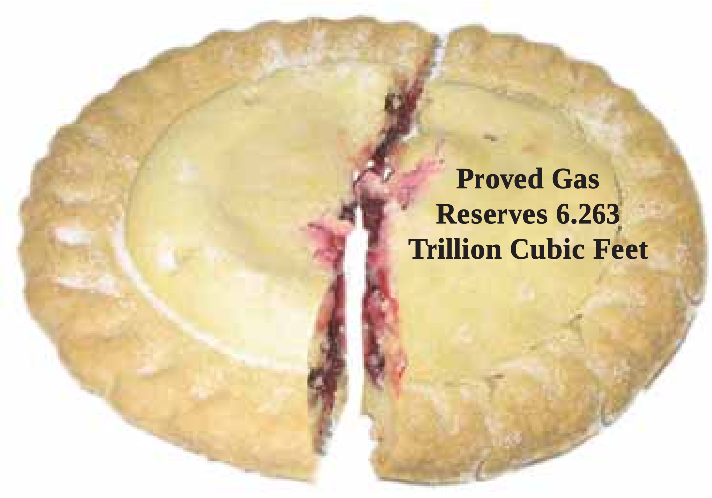


Figure 2 - The Total Size of the Gas Resource is 15.401 Trillion Cubic Feet (EPRasheed)

Before we go into detail, it is fair to note that the lack of a single international or institutionally recognised set of standards makes reserves measurement somewhat dependent on the system chosen[6].

Missing Barrels

With many oil companies based in the US or floated on US stock markets, the oil industry has been lobbying US regulators to overhaul the system by which the indus-try's reserves are measured[7].

The SEC classifies reserves using conservative and narrow definitions that do not satisfactorily account for the role of E & P technology in finding and producing reserves. This is a problem because not only does the industry have a track record of technology development, but technology is the stock-in-trade of the service companies and a principal measure by which analysts derive multiplier or share valuations of service companies beyond Earnings Before Income Tax Depreciation and Amortisation (EBITDA). Peak oil theorists also tend to minimise the value of E & P technology. We will examine the value of technology in detail shortly in the 'medieval map'.

The SEC measurement leads to a substantive variation with internal industry measures such as the SPE which places more emphasis on technology 'unlocking' reserves to make them more recoverable. The variation often results in discrepancies that amount to billions of barrels of oil across the industry[8].

Industry analysts have lobbied the SEC to change its reserves accounting so that the benefits of E & P technology can be better applied. Essentially, this covers a raft of technologies such as seismic, geosteering and horizontal drilling which enable higher recovery rates through pinpointing reserves and well placement[9]. At issue is the realistic valuation of energy companies themselves, as well as how we calculate replaced or future reserves. While analysts look to earnings as a short-term performance measure, the more long-term measure looks to reserves to production ratios as the basic indicator of the oil company's future wealth.

What's On the Books?

Due to the way financial and technological factors impact on reserves measurement, it is worth reviewing the types of reserves classifications that ultimately lead to KPI and valuation.

Getting a Slice of the Pie

It is worth distinguishing between the oil and gas resource and reserves. The 'global resource' is the 'size of the pie' or the entirety of the earth's oil and gas. The slice of this pie that is recoverable using today's technology at today's cost – price structure is known as 'global proved reserves'. According to BP's Statistical Review 2008, worldwide proved reserves of oil are 1.238 trillion barrels (see Figure 1) and those of gas are 6.263 trillion cubic feet (see Figure 2). The US Geological Survey, however, places the global resource of oil initially in place at 3 trillion barrels. We will come back to the size of the pie in the context of peak

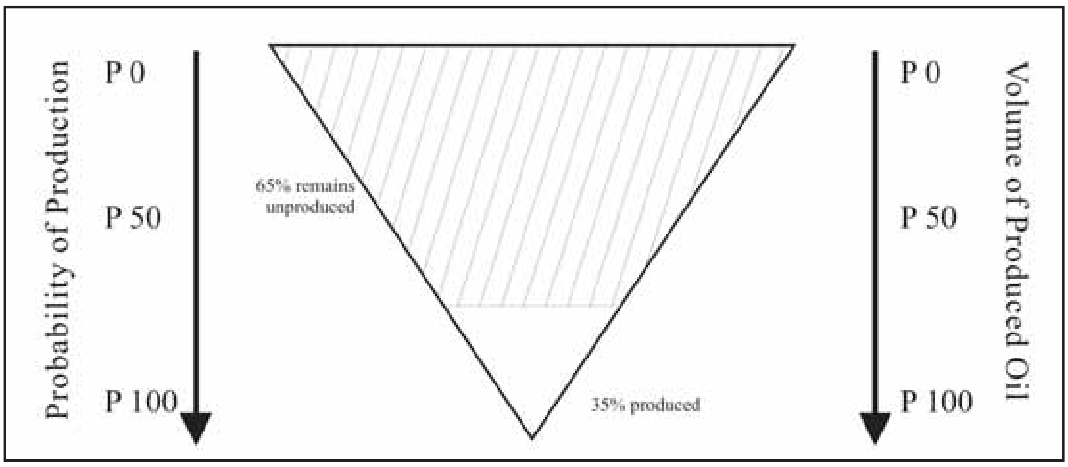


Figure 3 - The Relationship Between Probability and Volume of Oil Production (EPRasheed)

> "Reserves which can be produced economically through improved recovery techniques (such as water injection to maintain reservoir pressure) are included in the 'proved' classification when an increase in production is seen."

oil; however, for now it is worth noting that reserves are ranked based on their ultimate probability of production. That is to say one day in the future they will be brought to surface and sold.

Once the resource is discovered, reserves need to be booked. This process involves mapping out and visualising one or more underground structures (leads or prospects) that may extend over 200 square miles. Reserves must then be classified and assigned values according to the probability of their production. Finally, the value of reserves are discounted to today's worth. For financial and asset planning purposes, the key determinants are the likely size of discovered reserves and their ease of recovery[10].

The most common classifications are the generic three 'Ps' and the more specific 'P factor'.

The Three 'Ps'

Defined according to a sliding scale of the 'probability' or percentage chance of production, the three 'Ps'—Proved, Probable and Possible—are illustrated by the figure below. They indicate the relative ease or difficulty with which the reserves in question can be produced. It is standard practice for a numerical 'P factor' to be assigned to represent the specific probability of the reserves being produced. Typically, 'P' values for ultimate recovery range from P90 for a very high probability, P50 for medium probability and P10 for a very low probability. A series of questions related to location, accessibility and technology need to be answered before 'P' values can be ascertained. Are the reserves located in easily accessible areas or shallow depths? Are there wells, platforms or pipelines in place? Does the technology exist to reach the reserves today? If the answer is 'yes' to these questions, the probability of

> A common model defines a play as 'a set of known or postulated oil and/or gas accumulations sharing similar geologic, geographic, and temporal properties such as source rock, migration patterns, timing, trapping mechanisms, and hydrocarbon types'.

production is clearly high so these are proved reserves. Where the answer is 'no' and nothing is in place other than outline plans, such reserves are low probability. Most reserves will fall between these two extremes in that they have varying degrees of infrastructure in place.

Corresponding to a value, i.e. P 90, P 50 or P 10, the 'P factor' simply represents the percentage chance of reserves being produced. Proved is 90%, Probable is 50% and Possible is 10%[11].

This classification uses a scale based on the development status, the infrastructure in place and the ease of recovery of oil and gas. Reserves that score lower on development status and infrastructure are harder to develop so their percentage chance of recovery falls; therefore, they are assigned a lower 'P' class with a lower 'P' value.

'Proved reserves' refer to the estimated quantities of crude oil, natural gas and Natural Gas Liquids (NGLs) which can be recovered with demonstrable certainty using geological and engineering data. This applies, for example, to future production from known reservoirs under existing economic and operating conditions, i.e., oil prices and lifting costs as of the date the estimate is made.

Reservoirs are considered 'proved' if economic production is supported by actual production or conclusive formation tests showing an increase in production. The area of a reservoir considered proved includes: the portion identified by drilling and defined by gas-oil and/or

Figure 4 - The Americas Do Not Exist According to Medieval Maps

oil-water contacts and the immediately adjacent areas not yet drilled, but which can be reasonably expected as economically productive based on the available geological and engineering data[12].

Reserves which can be produced economically through improved recovery techniques (such as water injection to maintain reservoir pressure) are included in the 'proved' classification when an increase in production is seen. Estimates of proved reserves do not include the following: oil that may be produced from known reservoirs but is classified separately as 'indicated additional reserves'; crude oil, natural gas, and NGLs, the recovery of which is subject to uncertainty as to geological, reservoir characteristics, or economic factors; crude oil, natural gas, and NGLs that may occur in undrilled prospects; and, crude oil, natural gas, and NGLs that may be recovered from unconventional sources such as oil shales.

Further distinctions blur the boundaries between classes; for example, 'proved developed reserves' refers to reserves that can be recovered from existing wells using existing technology. Additional oil and gas production obtained through the application of improved recovery techniques can be included as 'proved developed reserves' only after successful testing. Tests can either be pilot projects or improved applications that show an actual increase in production.

'Proved undeveloped reserves' are reserves that are recoverable from new wells on undrilled acreage, or from existing wells where further major expenditure is required. Reserves on undrilled acreage are usually lim-

> "Technology is the stock-in-trade of the service companies and a principal measure by which analysts derive multiplier or share valuations of service companies beyond earnings."

ited to those areas where there is reasonable certainty of production when drilled. Proved reserves for other undrilled units can only be claimed where it can be demonstrated with certainty that there is continuity of production from the existing productive formation.

Russian and Norwegian Reserves Classification

Russian and Western methods of estimation and classification of reserves are somewhat different. The Russian officials have divided oil and gas reserves into six classes: A, B, C1, C2, D1 and D2. Class A represents proven reserves and B provable reserves. Class C1 represents reserves estimated by means of drilling and individual tests, and C2 reserves are based on seismic exploration. Classes D1 and D2 represent hypothetical and speculative reserves[13].

Norway uses its own definitions of reserves, which run from Category 0 – 9[14].

Category 0 is defined as 'Petroleum resources in deposits that have been produced and have passed the reserves reference point. It includes quantities from fields in production as well as from fields that have been permanently closed down'.

Category 9 includes resources in leads and unmapped resources and covers undiscovered, recoverable petroleum resources attached to leads. It is uncertain whether the leads, and if so the estimated resources, are actually present. The resource estimates reflect estimated volumes multiplied by the probability of making a discovery. This probability must be stated[15].

Geologic Assessment Procedures

Oil companies often use models to assess geologic structures or oil and gas plays. A common model defines a play as 'a set of known or postulated oil and/or gas accumulations sharing similar geologic, geo-

> Given that demand for oil and gas will rise in the long-term, and considering the track record of the E & P industry to date, further advances in E & P technology will permit almost all petroleum reserves, irrespective of location, to be developed before new energy sources and exits from the Hydrocarbon Highway are created.

graphic, and temporal properties such as source rock, migration patterns, timing, trapping mechanisms, and hydrocarbon types'.

Oil companies use this approach to process exploration knowledge such as seismic or aerial surveys or wildcats generated by the exploration teams. A fundamental part of this process is the attributing of probabilities for each petroleum play. Geologists will also assign subjective probability distributions to characterise attributes of undiscovered conventional oil and gas accumulations[16].

The geologic risk structure is modelled by assigning a probability to each play. This probability is based on at least one accumulation meeting the minimum size requirements (50 MMBO in place or 250 BCF gas recoverable). In particular, the oil company will assign probability distributions for reservoir attributes such as net reservoir thickness, area of closure, porosity and trap fill.

Net pay estimates are derived from the data and include the extent and distribution of the reservoir. These estimates are essentially refined and related to P values, i.e. P90, and are verified to see whether they are consistent with existing knowledge. Other factors to be considered will be hydrocarbon recovery factor, porosity and permeability forecasts and initial production[17].

> "The West African margin has been extended from the high-profile plays in the shallow waters of the Niger Delta, Nigeria and the Congo Basin, Angola to deeper waters and to highly prospective sub-salt plays."

Peak Oil and Medieval Maps

Since the publication of Hubbert's Peak in 1956, the theory of 'peak-oil' has gained in importance with a growing chorus of support from within the industry and wider society. Yet is peak oil really a physical decline in production levels or is it a philosophical debate mired in the minutiae of reserves and production systems?

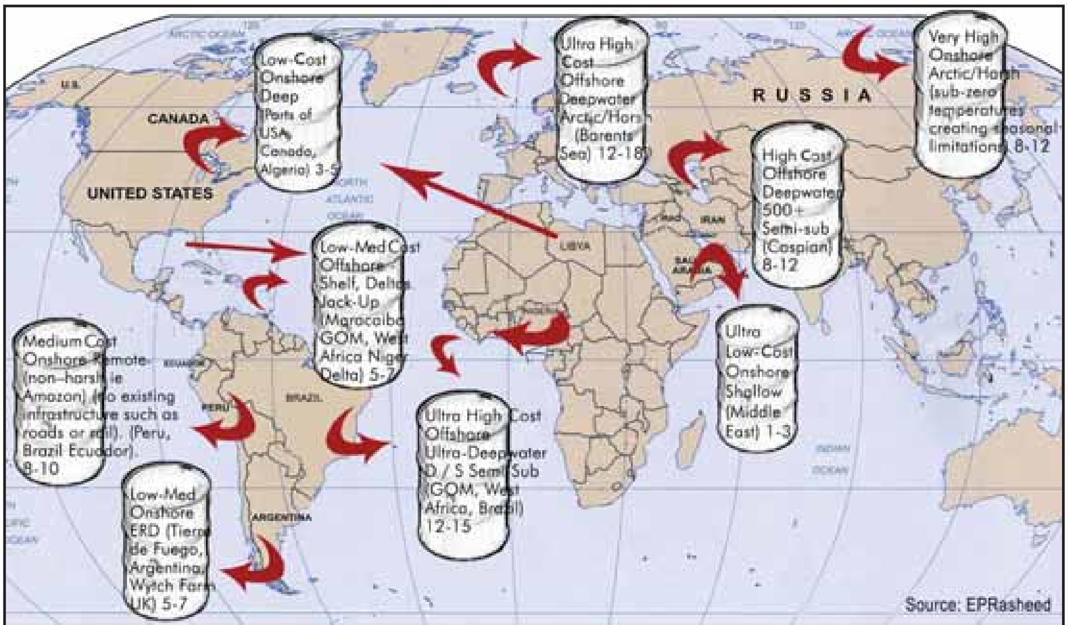
To answer these questions, we need to adopt a global E & P perspective that integrates prospective E & P areas with technology applications. Equally we need to recognise the limits of conventional wisdom. Are we navigating with a 'medieval map' of worldwide hydrocarbon reserves – one that does not adequately reflect the total resource?[18].

Optimist or Pessimist?

Two schools of thought exist. Optimists state there is an abundance of oil and gas and that there is enough for everyone, while pessimists state there is a deficit and we are doomed. These two positions, and the consequent debate, have generated much emotion, not to mention a multi-million dollar niche industry. What appears to be important here is that no-one disagrees that a peak or decline will occur, that is the natural state of systems. Yet, no-one can agree on when or even why this event will occur. It is worth considering this debate as it can help us understand the 'psychological' supply shortfall of prospects. This has a knock-on psychological effect on supply which is compounded by a herd mentality within the oil and gas markets (see *Chapter 12: Paper Barrels* for detail).

The pessimists reason as follows:

1. Rare conditions allow petroleum reserves to be



Note: Not included are development, lifting costs or production taxes/sharing agreement quotas. Based on several wells incl. 3D and sidetracks. Total depths vary. Deepwater includes adverse drilling challenges such as salt, tight ppfg, close tolerance casing and EPS early production system. Figures will vary depending on reservoir size. Does not include processing costs for heavy oil below 18 degree API which are by order of magnitude higher.

Figure 5 - Finding Costs for Oil Companies in US $

produced.
2. Once production peaks, reserves decline rapidly in output.
3. Most global petroleum reserves have peaked. Further large finds are unlikely.
4. Global production is therefore declining[19].

The optimists argue:

1. Rare conditions allow petroleum reserves to be produced.
2. Production can be made to plateau, not peak, through technology.
3. Technology finds more reserves, makes smaller reserves more accessible and sustains overall production on a global scale.
4. Global production is therefore sustainable[20].

There is also a third, or alternative view, to consider:

1. Rare conditions allow petroleum reserves to be produced.
2. Today's theories regarding petroleum reserves and recoverability are incomplete.
3. Knowledge increases over time.
4. Many prospective petroleum plays are unexplored.
5. All known sources of petroleum systems have therefore not yet been quantified; hence, the use of the 'medieval map' analogy[21].

In this alternate scenario, no one can state categorically that peak oil has, or has not occurred because our current knowledge is incomplete. Just as when we look at medieval maps and note the Americas are missing, so future generations will look at today's map of worldwide reserves as incomplete. Just as when previously wise petroleum engineers looked at deepwater reserves and shook their heads deeming them unrecoverable, we see the limits of their wisdom.

> "Game-changing technology such as 3D seismic improved the visualisation of reserves, while horizontal drilling and geosteering altered the definition of what was deemed uneconomic or unreachable at a given time."

Deepwater production has been made routine, almost mundane through 'game-changing' and cost-effective technology. This ranges from pre-drill packages that incorporate sub-salt imaging to seabed to surface risers to directional drilling techniques that can enable multiple reservoir completions.

In this way, the ultimate recoverability of reserves is tempered by the cost of technology. If E & P technology can be made available at cost-effective prices, reserves can be developed. This is because finding and lifting costs ultimately determine development. If the costs of development outweigh the price of oil, there simply is not enough profit to develop them.

As noted earlier, the SEC classifies reserves according to very narrow definitions that do not satisfactorily account for the role of E & P technology in finding and producing reserves. Peak oil theorists tend to use such classifications too.

Peak oil theorists tend to overlook the industry's track record of technology development. Technology is the stock-in-trade of the service companies and a principal measure by which analysts derive multiplier or share valuations of service companies beyond earnings.

This does not imply that petroleum is infinite. It means that even though petroleum is a finite and scarce resource, technology can increase production and ultimate recovery.

Aside from the technology factor, there is the question of the medieval map of reserves. As our globe-trotting exercise will show shortly, there are still several petroleum provinces waiting to be mapped out.

Given that demand for oil and gas will rise in the long-term, and considering the track record of the E & P industry to date, further advances in E & P technology will permit almost all petroleum reserves, irrespective

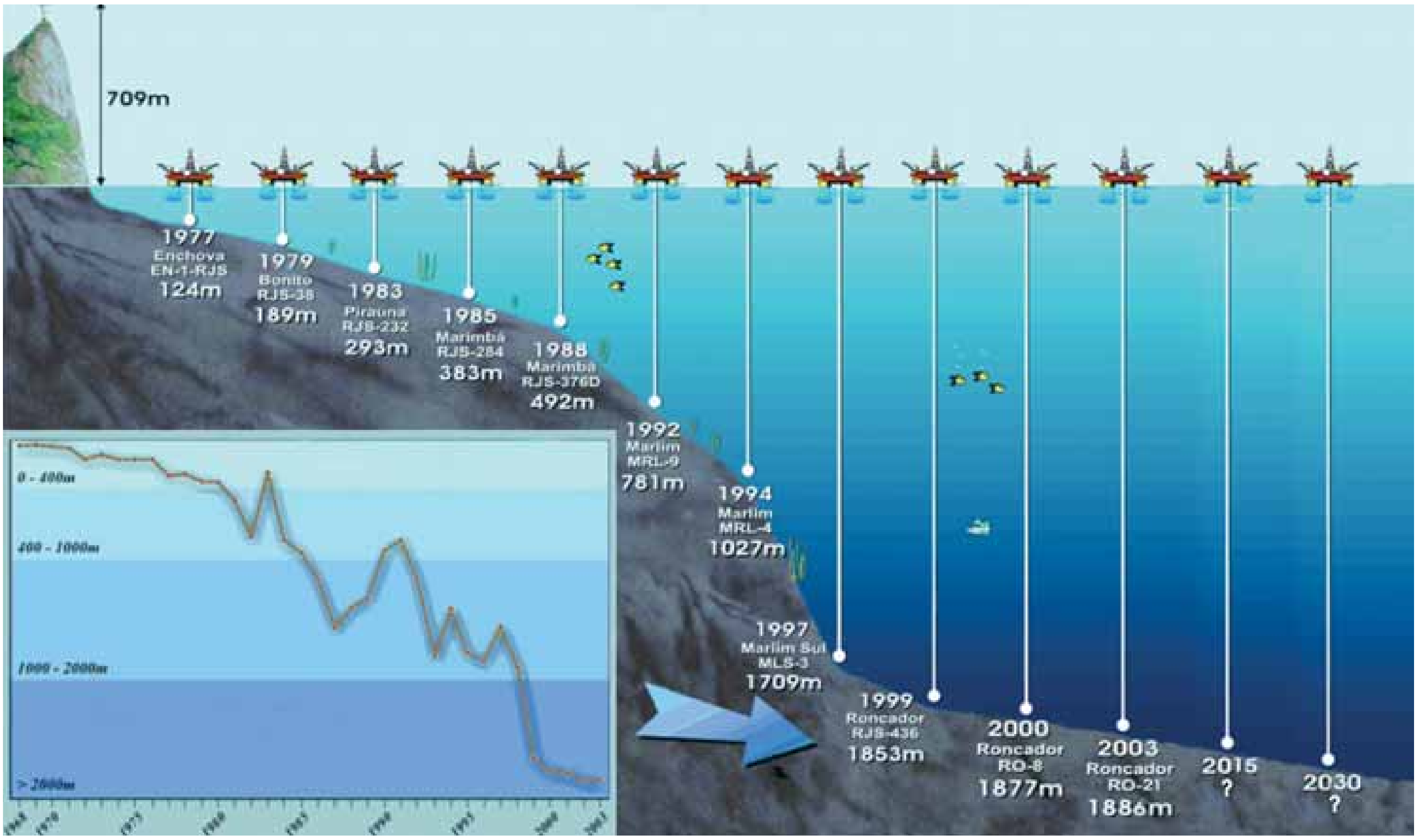


Figure 6 - The Incredible Depth Progression from Shelf to Deep Waters (Petrobras News Agency)

of location, to be developed before new energy sources and exits from the Hydrocarbon Highway are created. Consequently, the limiting factor for reserves will be the cost of development rather than their shortage.

Worldwide Reserves

Referred to as 'the low hanging fruit' that is effortlessly picked, onshore basins are generally easy-to-access with low finding and lifting costs. Consequently, these reserves have been both extensively characterised and produced; however, several tough-to-reach onshore basins remain unexplored. Exemplifying this is the Amazon Complex (Brazil, Colombia, Peru and Bolivia), the Arctic Circle (the Alaska National Wildlife Reserve being part of this territory) and Antarctica[22].

No one has any real knowledge on the potential size of these onshore reserves. The historic finding and lifting costs in similar areas such as Sakhalin or Alaska , however, range on average from US $12 to US $18. With production, total costs rise further due to a lack of infrastructure in remote areas (see *Chapter 8: Extreme E & P* for detail[23]).

Middle East

More prospective areas exist in unexplored basins within the Middle East such as the Empty Quarter (Rub Al Khali) in Saudi Arabia, the Bushehr province in Southern Iran and North and South Iraq. Typically, these countries are blessed with prolific source rock, high permeability and trapping systems found at very shallow depths starting at approximately 700 m (2,100 ft) and ranging to 2,000 m (6,000 ft). New finds continue to maintain the Middle East as a dominant long-term reserve base, with common recognition that Saudi Arabia and Iran respectively are the world's

> In addition to developing the technology to drill in deeper waters, the industry has developed the ability to drill extreme offsets from a single surface location.

largest and second largest holders of oil reserves. Further, finding, lifting and production costs are the lowest worldwide, averaging between US $1 to US $3 a barrel[24].

Lifting costs can vary, however, by way of comparison. In other relatively low-cost areas like Malaysia and Oman, lifting costs can range from US $3 to US $12 a barrel to produce. Production costs in Mexico and Russia might potentially be as low as US $6 to US $12 per barrel (higher under current production arrangements by local companies)[25].

By reviewing the world's prospective shallow coastal waters, deltas and oceans, it becomes clear that our map of global resources is incomplete. In the offshore realm, there are many unexplored basins with finding, lifting and production costs varying from US $18 to US $25 per barrel for certain deeper waters. Large tracts off the coast of West and North Africa are undeveloped. The West African margin has been extended from the high-profile plays in the shallow waters of the Niger Delta, Nigeria and the Congo Basin, Angola to deeper waters and to highly prospective sub-salt plays. Mauritania and Tanzania are other examples where new discoveries have been made[26].

South of Australia in Tasmania, oil companies have been studying gas plays since 2000 which had previously been neglected due to the search for oil. This has led to indications of oil being found in Africa near Madagascar, which has been identified as a potential new petroleum province[27]. Mauritania and Tanzania are other examples where new African discoveries have been made. Another area is offshore Morocco, where the deposition of an ancient river system was found over salt. A mobile substrate, either salt or shale, is a key element all along the West African margin because it provides geological factors necessary for oil and gas[28].

Continental Plate Reconstruction

A clear example of continental plate reconstruction and conjugate oil and gas of plays is offshore West Africa and offshore Brazil. By using reconstructions, it can be seen that the Rio Muni Basin was the 'mirror' basin to the Sergipe-Alagoas Basin in Brazil, and the Congo Basin to the Campos Basin. By repeating this

> In river deltas worldwide, as the shallow water plays were developed, exploration efforts evolved into the deepwater usually with only major international oil companies that could qualify for the blocks.

process along the coast of West Africa and Brazil, several emerging oil and gas plays can be drawn up. These include the sub-salt frontiers of offshore Brazil including Tupi. Although production is not likely to make a major impact on world oil exports over the next decade, the point is that new frontiers have been discovered[29].

In Central America, the offshore area between Venezuela and Trinidad, the Gulf of Paria, is largely unexplored as are the waters off Colombia and Peru[30].

The Gulf of Mexico (GOM) has unexplored waters that stretch from the shallow waters off Florida, US and move into the territorial GOM waters of Cuba, vast areas of deep waters in the Mexican GOM and the deeper waters of the US GOM. Within the US GOM, the sub-salt play has been instrumental in new finds.

Offshore production in areas like the North Sea with offshore platforms, can run to US $12 to US $18 a barrel. As reservoirs become smaller, those costs tend to rise. In Texas and other US and Canadian fields, where deep wells and small reservoirs make production especially expensive, costs can run above US $20 a barrel.

Further East, we note that certain areas of the Northern North Sea and the Barents Sea are still to be explored. While in Russia, Sakhalin Island, the Central Asian Republics, the Red Sea, the Persian Gulf, the Indian Ocean, Offshore Australia and New Zealand, several offshore basins represent prospective yet unexplored areas[31].

What is the total resource base? The US Geological Survey puts this at 3 trillion barrels of oil. Again, it's hard to say because we are still waiting to finalise the map.

Sweating

The Finding and Development in Figure 5 clearly shows that, when crude oil prices fall below US $20 a barrel, many areas become unprofitable and

> "The billion-dollar think tanks and research and development facilities that major service companies own are continually creating new technologies that help access reserves previously considered uneconomic or unreachable."

production is reduced if not halted altogether. Only certain lower cost areas can remain profitable and hence maintain production during a 'good sweating' period[32].

Two factors emerge from this globe-trotting exercise: first, there is a lack of characterisation in many highly prospective basins and gulfs; and second, there is high prospectivity, but it is tempered by technical limitations and increased costs.

None of these areas is mature; most are unexplored and some are even unlicensed. This is despite adjoining proven hydrocarbon producing basins or sharing geological characteristics such as source rock, trapping and faulting. It is fair to say that we have not yet characterised the world's oil and gas basins nor their accompanying reserves. Consequently, how can we even assume that global peak oil production has occurred? (Gas is another matter entirely as it can be man-made).

Conventional Wisdom and the Limits of Our Map

The limitations of our map of oil and gas reserves start to become clear when we consider past theories. In the 1990s, one widely held view stated that offshore oil and gas reserves would not be found at extreme conditions, i.e. depths exceeding a TVD of 20,000 ft (6,096 m). It was suggested that overburden pressures would either cause a loss of hydrocarbons due to migration to shallower traps or compaction[33]. Now that theory has changed because oil and gas trends have been located at far greater depths than prior knowledge would indicate. Think deep gas, US GOM.

In the 1980s, another example of a change in thinking occurred concerning the flow paths of fluvial deposition. Ancient river systems account for the sedimentation that leads to accumulations of oil and gas. In river deltas worldwide, as the shallow water plays were developed, exploration efforts evolved into the deepwater usually with only major international oil companies

> "The buzzwords of 'ultra-deepwater, digital oilfield and barrel-chasing' may first be heard in oil company offices due to the engineering challenges and risks oil companies 'buy'."

that could qualify for the blocks[34].

Smaller oil companies, therefore, were limited to exploring other geologic scenarios and plays. They recognised that over time the places where these river systems had been depositing sediment had changed, and the Independents' exploration discovered 'new' margins.

Another example of limited knowledge has been sub-salt basins. These have been discovered and are being explored in the GOM and worldwide. Sub-salt plays in West Africa, Brazil and GOM show deeper accumulations of oil and gas trends that had not been predicted or expected earlier.

Game-Changing Technology

Back in the late 1980s, it was thought that development of thin sands such as 'Norwegian Troll oil' would never be economically feasible, because the oil reserves were so thinly layered and the price of oil was US $10 per barrel. Game-changing technology such as 3D seismic improved the visualisation of reserves, while horizontal drilling and geosteering altered the definition of what was deemed uneconomic or unreachable at a given time. The billion-dollar think tanks and research and development facilities that major service companies own are continually creating new technologies that help access reserves previously considered uneconomic or unreachable. Service companies and operators develop technology in-house through joint industry projects and with best-in-class companies; for example, Shell and Petrobras respectively are involved in the monobore and the Procap 3000 initiatives—two examples of technology cascading downward. Underlying the monobore (a vision of drilling and casing a single-diameter well from top to bottom) is the creation of

> Records are continually set and broken not just in deeper water depths (3,000 m) but also in deep reservoirs below salt domes, tar zones and in the remote basins of the world and in new frontiers.

businesses to develop the downhole tools, tubes and markets for expandable tubulars. 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 dual-activity derrick system[35].

Technology

Scarcity of oil reserves and increasing reserve replacement costs are the twin factors that have accelerated the technological evolution of E & P and enabled extreme E & P (see *Chapter 8: Extreme E & P*). This evolution is most clearly visualised in the dramatic shift from onshore to offshore exploration. The incredible depth progression from land to shallow coastal waters to deep waters to the extremes of ultra-deepwater is shown in the graphic below[36].

A few decades ago, it was not considered possible to produce in waters beyond 6,561 ft (2,000 m) depth, and accordingly, those reserves were listed as 'P 10s' with a very low possibility of production. Rigs and risers were just some of the incredible challenges. The industry has, however, progressively tapped deepwater accumulations. First, it targeted shallow onshore reserves as the less challenging 'low-hanging fruit'. As those resources became scarcer, E & P went deeper onshore and spread to shallow offshore waters. E & P operations in 8,200 ft (2,500 m) water depth are routine, and the challenge now is 9,842 ft (3,000 m) and deeper.

Records are continually set and broken not just in deeper water depths (3,000 m) but also in deep reservoirs below salt domes, tar zones and in the remote basins of the world and in new frontiers. This includes the latest subsea water separation systems and subsea sand separation to achieve maximum production. Remarkably, however, almost all of this enabling E & P technology is considered an outsourced commodity marketed by service and supply companies, which means the NOCs have no shortage of technology vendors. The buzzwords of 'ultra-deepwater, digital oilfield and barrel-chasing' may first be heard in oil company offices due to the engineering challenges and risks oil companies 'buy'. They resonate most loudly, however,

> In addition to developing the technology to drill in deeper waters, the industry has developed the ability to drill extreme offsets from a single surface location.

throughout the service-side: in product development, in research facilities and on test rigs before technology is commercially run in field applications[37].

In addition to developing the technology to drill in deeper waters, the industry has developed the ability to drill extreme offsets from a single surface location. This has profound implications in reducing our environmental 'footprint' and providing economic access to thousands of 'satellite fields'. As of 2008, the world's record Extended Reach Drilling (ERD) well was drilled in the Persian Gulf from a jack-up drilling rig. The total measured depth of the well was 40,320 ft (12,293 m), and the well's bottom was offset 37,956 ft (11,572 m) from its surface location. In the UK, ERD techniques enabled BP to develop Wytch Farm, an entire oil field under an environmentally sensitive resort and vacation area on the south coast of England, with no visible footprint. Off Sakhalin Island in far east Siberia, Russian companies are exploiting oil reservoirs from land by drilling ERD wells out under sea ice that would ordinarily damage offshore facilities.

These feats were inconceivable to Hubbert when he developed his peak oil theory. Hubbert was correct to state that oil is a finite resource – and he can't be blamed for letting a medieval mentality affect his prediction of when we would run out. People today who are still letting medieval thinking guide them, however, should know better.

What emerges from the peak oil debate is that we are reading the directions to worldwide reserves from a 'medieval map'. Clearly, there are new frontiers and plays to be developed. Think Subsalt, Arctic and Deepwater E & P which is changing the definition of P 10's into P 90's. Coupling this with innovative thinking and cutting-edge technology makes for a convincing argument; peak oil as far as reserves are concerned, is a philosophical debate rooted in a psychological shortage not a physical one.

We are not in fact running out of oil. We have many areas yet to explore before we have to worry about oil and gas shortages. As we have been shown, there are plenty of barrels of oil remaining. The next logical question then would be 'What is in a barrel of oil?' Everyone always talks about barrels, but no really talks about their composition or how this affects recovery.

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> "Service companies and operators develop technology in-house through joint industry projects and with best-in-class companies..."

2. The OPEC Statute requires OPEC to pursue stability and harmony in the petroleum market for the benefit of both oil producers and consumers. To this end, OPEC Member Countries respond to market fundamentals and forecast developments by co-ordinating their petroleum policies.

3. See Booklet: What is OPEC? Production regulations are simply one possible response. If demand grows, or some oil producers are producing less oil, OPEC can increase its oil production in order to prevent a sudden rise in prices. OPEC might also reduce its oil production in response to market conditions. Public Relations & Information Department, OPEC Secretariat, Obere Donaustrasse 93, A–1020 Vienna, Austria. Tel: +43 1 211 12-279, (www.opec.org).

4. See Oil and Gas Reserves Committee (OGRC) "Mapping" Subcommittee Final Report – December 2005 p 14, Russian Reserves Classification based on Russian Ministry of Natural Resources (RF-2005).

5. Ditto p 16 Norwegian based on Norwegian Petroleum Directorate (NPD–2001).

6. There are as many as 7 different reserves classification systems in practice.

7. The SPE is seeking to overhaul and standardize current classification methods.

8. The Industry is lobbying the SEC for a rule change.

9. E & P technology clearly make reserves more accessible. The problem is at what cost? The issue is not simply related to oil price v technology cost but certainly more account should be made of the role of technology and reserves classifications.

10. This is what determines asset valuation and cash flow.

11. Standard knowledge in the industry.

12. See SPE (OGRC) "Mapping" Subcommittee Final Report Definition of Proved Reserves page 31.

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14. Ditto p 16 Norwegian Classifications.

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19. Communications with Dr Colin Campbell, one of the leading voices of Peak Oil.

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28. See AAPG Explorer Magazine Nov 2002 Kathy Shirley.

29. See Brazil Oil and Gas Issue 11 p 6 Tupi's recoverable volume of 5 to 8 billion barrels of oil equivalent may place Brazil in the select group of petroleum exporting countries (www.braziloilandgas.com/issue10).

In 2008, Petrobras announced new oil discoveries in the Santos, Espírito Santo, Campos, and Jequitinhonha Basins. In the Santos Basin pre-salt layer alone, the company estimates recoverable volumes of 9.5 billion and 14 billion barrels of oil and gas in barrel equivalent in the Tupi, Iara, and Jupiter areas. In September 2008, the Company started producing in the pre-salt in the Espírito Santo sea, in the Jubarte Field, located in the Campos Basin.

30. The Identification of The Depositional Environments Of The Cruse, Forest And Morne L'Enfer Formations In The Southern Half Of The Gulf Of Paria, Trinidad, West Indies Curtis Archie, PetroTrin.

31. Oil from the South: Mesozoic Petroleum Systems, Proven and Potential, in Mid to High Southerly Latitudes Bradshaw, Marita et al. Is there a corresponding belt of petroliferous basins in the southern hemisphere? Notable oil provinces do occur in mid to high southerly latitudes. Oil source rocks include marine Early Cretaceous shales (San Jorge and Magallanes/Austral basins, South America; Bredasdorp Basin, South Africa) and Late Cretaceous to Eocene coaly sediments (Gippsland Basin, south-east Australia; Taranaki Basin, New Zealand). Frontier Mesozoic rift basins occur in offshore East Africa, along Australia's southern margin (Bight and Mentelle basins), on the Lord Howe Rise, offshore New Zealand and in the Falklands. Regional studies of the shared history of Gondwana breakup and paleoclimatic and environmental reconstructions can guide exploration in these frontier areas.

32. See page 230 The Prize: The epic quest for Oil, Money and Power Daniel Yergin Publisher: Simon and Schuster (Jan 01 1993) ISBN: 0671799320.

33. AAPG Explorer, October 2008, Independents Find Africa Success.

34. Gas Beckons in Deep Shallows. Louise Durham Gas exploration to depths of 30,000 ft.

35. The Discoverer Enterprise of Transocean is the first ultra-deepwater drillship with dual activity drilling technology, which aims to reduce the cost of an ultra-deepwater development project by up to 40 percent. Two full-sized rotary tables are designed into a drill floor more than twice as large as a conventional one.

36. The industry is looking at ultra-deepwater as 3,000 m.

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

38. See The Medieval Map page 45.

39. Campbell, Peak Oil … Hubberts Peak: The Impending World Oil Shortage Deffyes.

40. Author's notes on acreage in emerging markets.

41. Lifting costs EPRasheed.

42. Idem.

43. The End of Oil: On the Edge of a Perilous New World Roberts Publisher: Houghton Mifflin; (May 15, 2004) 400 pages ISBN: 0618239774.

44. AAPG Morocco substrate.

45. Deepwater plays are among the most complex, high cost projects requiring large capital investment therefore favouring large IOCs.

46. Expand your mind, Harts E & P 2004 Wajid Rasheed.

47. Petrobras evolution offshore.

48. The Oil Factor: How Oil Controls the Economy and Your Financial Future Donna & Stephen Leeb Published: February, 2004 ISBN: 0446533173.

49. Coming Oil Crisis, Campbell Publisher: Multi-Science Publishing Co. Ltd.; (April 1, 2004) 210 pages ISBN: 0906522110.

50. Hubberts Peak: The Impending World Oil Shortage Deffyes Publisher: Princeton University Press; (August 11, 2003) 224 pages ISBN: 0691116253.

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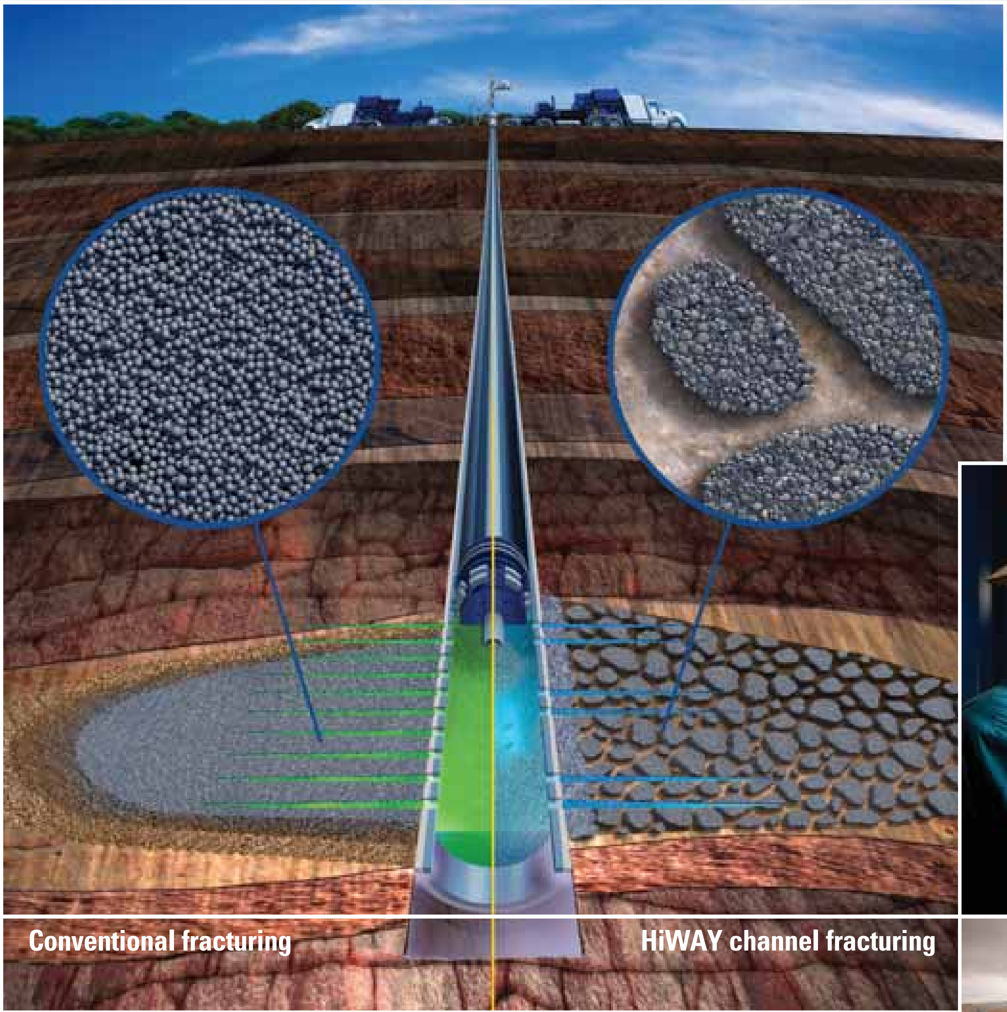

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