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Saudi Arabia oil & gas

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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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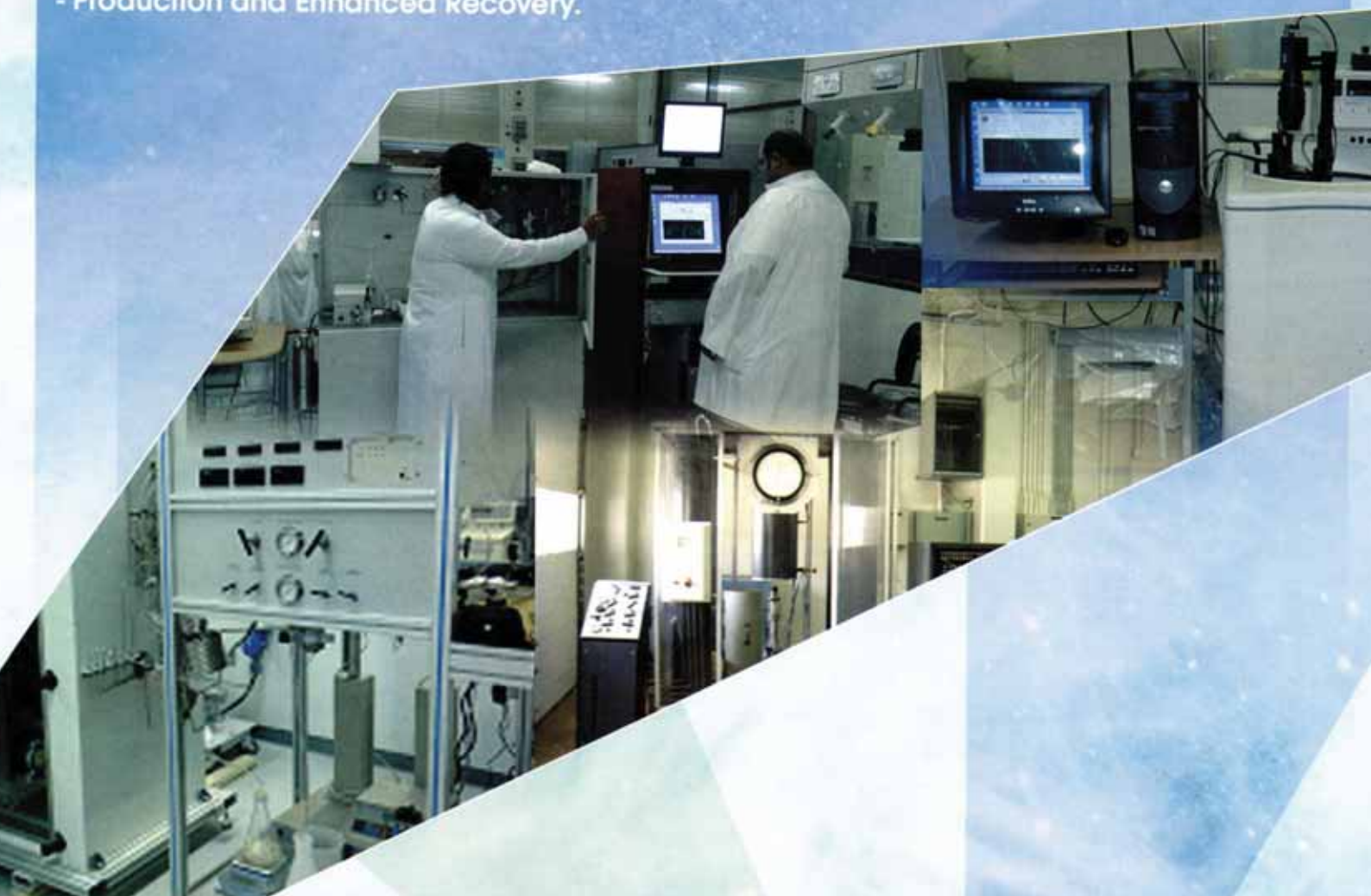
- Drilling Engineering,
- Rock Mechanics,
- Production and Enhanced Recovery.



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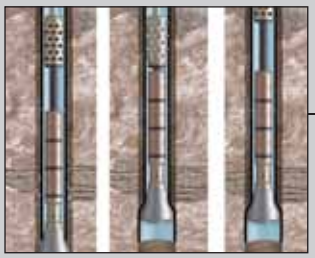

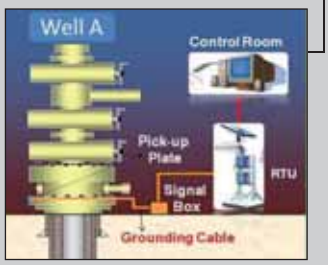

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Welcome Message from the Chairman, 2012 SPE/DGS Annual Technical Symposium & Exhibition

It gives me great pleasure to welcome you to the 2012 Annual Technical Symposium and Exhibition (2012 ATS&E). This event is organized by the Saudi Arabian Section of the Society of Petroleum Engineers (SPE SAS).

This gathering of petroleum professionals has taken center stage as the premier annual gathering for the petroleum industry in the region. Over the years, the Symposium has grown considerably to become one of the major gatherings for knowledge transfer and experience sharing in the Gulf region. 2012 was different in terms of attraction, with more than 300 abstracts submitted from over 28 countries.

This year's theme is "Unconventional Transformation of Our Energy Future". It is a call for all professionals to share knowledge and discuss merging technologies that affect unconventional resources recovery, improved drilling operations, effective stimulation and next generation simulation modeling. These technologies and best practices will be the transformation engine of our energy future.

The 2012 Annual Technical Symposium offers a rich program that consist of four pre-event courses, 18 technical sessions, one poster session and a major panel discussion. In addition, there will be an exhibition showcasing new technology advancements. This program will be complemented by recognized keynote and distinguished speakers.

On behalf of the program committee, I would like to thank you for your support in making the 2012 SPE SAS Annual Technical Symposium and Exhibition a grand success, wishing that you find it a rewarding experience. I would also like to thank Saudi Arabia Oil and Gas in its fifth year as the official journal.

Abdullatif A. Al-Omair
Chairman, 2012 SPE SAS Annual Technical Symposium & Exhibition

YASREF Board Holds First JV Meeting

SEOUL, Republic of South Korea , 21-Mar-2012

The Board of Directors for the Yanbu Aramco Sinopec Refining Company (YASREF) Limited, a joint venture between Saudi Aramco and China Petrochemical Corporation (Sinopec), was held recently in Seoul.

The meeting was conducted by the board chairman, Khalid Al-Buainain, with representation from the joint venture partners, including Fahad Al-Helal, Khalid Al-Naji and Salah Al-Hareky from Saudi Aramco, and Ling Yiqun and Zhou Xinqian from Sinopec.

The YASREF Board reviewed and confirmed the new board members and committee members, and the appointment of new company officers, along with other administrative items. Also presented as information items were the 2011 year-end financial results and the company's development plans, including the ongoing apprentice program and direct-hire recruitment programs for 2012. The Project Execution Status was also presented, showing the project's construction being 5 percent ahead of schedule at 12 percent, engineering being 2 percent ahead of schedule at 79 percent, and procurement being on schedule at 41 percent.

The joint venture refinery now being built by YASREF will be in the Royal Commission of Yanbu'. It will be a world-class full-conversion refinery using 400,000 barrels per day (bpd) of Arab Heavy crude that will produce ultra-clean transportation fuels for international and domestic markets. After commissioning and start-up, the single-train refinery will produce 263,000 bpd of diesel, 90,000 bpd of gasoline, 140,000 tons per day (tpd) of benzene, 1,200 tpd of pelletized sulfur, along with 6,300 tpd of petroleum coke. The construction is expected to be completed in June 2014, with start-up commencing in September 2014 and the first commercial shipment of refined products expected in the fourth quarter of 2014.

Within a few years of operation, YASREF is expected to deliver significant annual revenues and generate about 6,000 direct and indirect jobs for Saudis. Also, the joint venture has enrolled 550 Saudis in the apprentice program, with the majority of the apprentices to be assigned to operations and maintenance activities in the refinery.

The refinery is using proprietary technology supplied by UOP, Chevron Lummis and ConocoPhillips to assure the quality and quantity of the ultra-clean transportation fuels produced. All of the refinery's products will be marketed and sold to the world on behalf of YASREF by the joint venture partners.

Korean Saudi Aramco School Students Travel to Distant Shores

DHAHRAN, Saudi Arabia, 21-Mar-2012

"For six months, my students have been excited to come [to Dhahran]," said Jeon Hyoung Jae, principal of Eungye Middle School (EMS) in Sihung, South Korea, during his speech in a luncheon hosted by Dhahran Saudi Aramco Schools. Exploring the culture of the Kingdom "should give us a new perspective in life," he added.

Korean students visited Saudi Aramco Schools in Dhahran for 10 days as a part of the friendship program between the two schools. This trip was the first international travel experience for many of the visiting students.

Some were excited to experience the Kingdom's desert climate. "We do not even have dust [in Korea]," said Dong Gyune Kim of EMS. Others were eager to discover some Saudi history because of the country's uniqueness.

The Korean students wasted little time before acclimating, kicking off their visit by joining fellow students for a Winter Dance. In Dhahran, the students learned about Saudi Aramco and the community's history during a visit to the Heritage Gallery. In al-Hasa, the students visited Ibrahim Palace and the old market, and they later flew to Shaybah to see up close the company's operations.

A day was devoted to a workshop about Korean culture for students from Saudi Aramco Schools who are planning to go on the trip to Korea. As part of the program, the exchange students shadowed their hosts in the Dhahran school for a day.

"It is interesting that students here get the chance to have discussions about what they think," said Seukwon.

Meanwhile, the two teachers who volunteered to accompany the students had the chance to observe the school's educational philosophy. "Whereas some schools focus on making students get high grades in exams, this school [SA school] makes students confident in everything," said Korean English teacher Mina Kim.

The student exchange program started in 2008 to culturally enrich the trip for SAS students who travel to Korea. Instead of only seeing the tourists' sites, students now have the chance to go into Eungye Middle School and stay a night with a host family.

"The highlight of the trip for the kids usually is the home stay with the family because they get firsthand experience of the Korean culture," said program coordinator Alice Underwood. "For the Korean students, it is about getting out of the [Korean] Peninsula," seeing a different country and how big the world is beyond the Republic, she added.

Every two years in January, 10 Korean students and two Korean staff members come to Dhahran. In March, a group of Saudi Aramco school students travels to Korea.

"Teens are curious about what their peers do in other countries," Heather Aberle, one of the coordinators said.

Dong Gyune Kim said his parents supported his decision to participate in the program because they wanted him to be open to other cultures and learn to become competitive in a global market.

Saudi Aramco Reaffirms Partnership with King Faisal University

AL-HASA, Saudi Arabia, 13-Mar-2012

Saudi Aramco and King Faisal University (KFU) reaffirmed their existing successful partnership with a full-day visit by a Saudi Aramco delegation to the university.

The meeting was an opportunity to identify areas for future collaboration with a focus on engineering and project management. HE Dr. Yousuf Al-Jandan, KFU president, opened the meeting by extending a warm welcome to the visiting delegates, including senior vice president of Engineering and Project Management Abdullatif A. Al-Othman.

Al-Othman expressed his admiration of KFU achievements over the past years and reiterated Saudi Aramco's continuous support for the university in achieving its goals through solid and sustainable collaboration.

The meeting included an introduction of the university structure and academic programs, an overview of the College of Engineering, a presentation on the university's strategic plan and an overview of university research and development activities. A tour of the new university campus was conducted and included the university's new broadcasting station and theater.

The visit resulted in defining specific collaborative actions, which includes the formation of a Saudi Aramco steering committee chaired by Omar S. Bazuhair, executive director of Engineering Services.

This committee has been tasked to work with KFU on translating these identified actions into implementable programs with appropriate monitoring and follow-up mechanisms.

KFU has 16 colleges that offer 59 undergraduate programs. The university hosts a total of 30,873 full-time undergraduate students, of which about 62 percent are female students. The university is completing a massive campus that will provide a modern and effective learning environment.

ASC Facilitates Joint KFUPM-Stanford Geology Field Seminar

HOUSTON, Texas, USA, 13-Mar-2012

Geology students and faculty members from King Fahd University of Petroleum and Minerals (KFUPM) and Stanford University, with support from Aramco Services Co. (ASC), recently conducted a joint field seminar in Death Valley, California.

The group of 26 gained hands-on experience in recognizing and interpreting sedimentary environments while fostering ongoing collaboration between the two universities.

Before leaving for Death Valley, the delegation from KFUPM and ASC toured the Stanford campus and met with Stanford faculty members Dr. Roland Horne and Dr. Jerry Harris to learn about programs in petroleum engineering and geophysics.

The following day, led by Stanford Geology Professor Dr. Don Lowe, a convoy of five SUVs drove from Palo Alto to Death Valley National Park. The next five days involved hikes, some at a distance of 10 miles, to view geologic features such as alluvial fans, sand dunes, playas and ancient glacial, shallow-marine and deep-water deposits.

During the evenings, students and faculty members presented their research topics, many including field photographs from Saudi Arabia, California, New Zealand, South Africa and South America that rivaled the natural beauty of Death Valley.

Many members of the group have connected on Facebook so they can exchange photographs and keep in contact about projects of interest. The faculty members and ASC Upstream Research staff are already discussing plans for the next joint field seminar, possibly in Saudi Arabia.

Al-Khayyal Speaks at ASIS Security Conference

DUBAI, United Arab Emirates, 20-Feb-2012

"Lt. General Dhahi Khalfan Tamim, distinguished guests, ladies and gentlemen:

Good morning.

It is a special pleasure to join you for the third annual ASIS International Middle East Security Conference, as the good work we began at the initial conference builds momentum. Saudi Aramco is very proud of its 36-year association with ASIS International, and on behalf of the company I appreciate this opportunity to share with you some thoughts on organizational resiliency.

Today, I will discuss how the implementation of global standards will allow for the scaled and phased implementation of maturing security programs in a market-driven economy. We will look at how compliance helps us perform to the demands of the market and deliver prosperity, transparency, accountability and functionality.

We'll also consider these issues from a regional context, to show how the Middle East can achieve these things and be a leader in organizational resiliency.

There was a time not so long ago, ladies and gentlemen, when business and industry took a straightforward, conventional view of security. We perceived it in the most literal terms: the uniformed guard in the office lobby, or stationed at the company gates.

In this mindset, security was further compartmentalized as the province of a narrow margin of businesses requiring specialized security personnel – like financial institutions or very large commercial and industrial enterprises. Even within those boundaries, it was common to limit the scope of security further still, to applications like asset protection or loss prevention.

As a result, security was often a secondary, supporting measure – thus it was largely reactive, working to contain harm more than to prevent it.

Today, we know that security has vital applications for every type of business and industry, and covers a full spectrum of activities and interests. In fact, part of our message at this conference must be for business and industry to move away from such arbitrary limitations toward a comprehensive approach.

Ladies and gentlemen, a paradigm that might have been appropriate even two decades ago has been rendered obsolete, as globalization, technology, interconnectivity, information and automation affect how each of us does business today.

And this dynamic, rapid-change environment in which we all operate adds urgency to our security activities. Our ever-shrinking, high-tech world, where time and distance barriers are virtually erased, creates vulnerabilities even as it affords convenience, speed and other business benefits.

> "... a paradigm that might have been appropriate even two decades ago has been rendered obsolete, as globalization, technology, interconnectivity, information and automation affect how each of us does business today."

In such a world, relegating operational risk management to line-item status actually elevates the likelihood of disruption – especially in a tight economy, when many companies tend to see security as an expense, rather than an investment.

This reality, my friends, is why we have the organizational resiliency standard.

By giving organizations and their supply chains an integrated framework and best practices for greater resiliency, standards can address a range of operational risk management from anticipating, assessing and preparing for risk; to preventing, mitigating and managing it… a strategy that takes us all the way through to continuity and recovery.

The first step on the path to resiliency is rethinking the equation:

Risk equals threat plus consequences, plus vulnerability.

When risk is inherent, the question becomes how much risk is acceptable, and how we are going to manage it, given finite resources.

That question is best addressed by taking a 360-degree view of business, and finding where our vulnerabilities and threats lie.

Of course, when we think about drivers impacting our security management mindset, man-made threat is the first big-change element that comes to mind. But rethinking security management means taking the broadest survey from an all-hazards approach.

Why? Two reasons: because we tend to overlook the obvious, and because success can breed complacency.

Consider natural risk. If your building catches fire, insurance can cover the replacement of furnishings, equipment and the building itself. But what kind of plan is in place to ensure the continuity of your operations, and the protection of your human, physical, intangible, and environmental assets, while matters are being sorted out?

The elements don't have to destroy outright to adversely affect operations.

A broken water pipe that floods your offices may seem

> When the virtual realm is driven by rapid change, and the speed-to-market mentality does not allow for policies and processes to catch up to technology, the threat of sabotage grows.

a relatively minor inconvenience until you consider where your people are going to sit and do their work. Or a road construction crew digging on the street could inadvertently cut a fiber-optic line, wiping out your Internet, telephone and cellular access for hours, through no fault of your own – but disrupting business, nonetheless.

Clearly, if we are to achieve sustainable operations, our security master plan must incorporate crisis management planning to ensure competitiveness and performance.

Continuing that 360-degree view, we see how information, technology and connectivity – the very advances and conveniences that have revolutionized how the world does business – also place us at greater risk.

Malicious attempts to access private information or resources – the gamut of network scanning or data sniffing, hacking, virus attacks, email spoofing and spamming – can result in compromised and corrupted data, interrupted operations and lost assets.

When the virtual realm is driven by rapid change, and the speed-to-market mentality does not allow for policies and processes to catch up to technology, the threat of sabotage grows. All the more reason for agile, proactive security measures that are interwoven into operations at every level.

Seemingly mundane events, if dealt with proactively, can be contained as a manageable inconvenience or interruption, rather than a costly, protracted, or even catastrophic event.

However, physical and environmental harm are only part of the damage that can result when security is not fully integrated into operations.

Reputational embarrassment – damage to the company brand – can devastate the bottom line every bit as much, and spread beyond the individual organization to affect the field or industry – and even governments.

The Information Age that makes widespread, immediate communication possible also carries the risk of devastation detectable only after the damage has been done. A quick look at the headlines on any given day provides ample evidence; Wikileaks and Anonymous are just two examples.

The news delivers constant reminders that today, when anyone on the street can use a phone to capture an event

> Seemingly mundane events, if dealt with proactively, can be contained as a manageable inconvenience or interruption, rather than a costly, protracted, or even catastrophic event.

as it unfolds and immediately post video and images to the Web, an organization not guided by standards of transparency, integrity, accountability and good corporate citizenship operates in peril.

The tragic Macondo well incident in the Gulf of Mexico was devastating on many levels: the loss of human life, foremost; the environmental harm that affected the lives and livelihoods of states along the Gulf, and the harm to animals and ecosystems. This catastrophe resulted in tremendous financial loss, and the reputational harm touched the global petroleum industry by association.

In all truth, when trouble can arise despite our best intentions, the only course of action is preparedness.

At Saudi Aramco, for example, preparedness includes putting contingency plans into a real-world environment through proactive emergency drills in keeping with industry best practices.

This kind of planning has the additional benefit of aiding transparency – both as an auditing and governance tool, but also for the credibility conveyed, and good will generated, by open, balanced and impartial business operations.

My friends, when we compare the traditional, silo security paradigm we talked about earlier with the integrated security model, it makes sense to weave security into every aspect of our operations.

Perhaps the most fundamental step toward integration is cultivating a security culture: and like any meaningful business policy, it has to start at the top.

Security must have the endorsement of executive leadership, who not only communicate it throughout the ranks, but also enforce it. It stands to reason, therefore, that the chief executive officer must also be the chief security officer.

This is not to suggest that the boss should run the security program; clearly, that's what you, the security professionals, are there for. What this visible leadership does is give every employee a stake in protecting the company's critical assets. It affirms that skimping on security will in fact carry a devastating cost.

Such visible leadership also brings us back again to transparency, which equals operational integrity.

The interwoven security model is also manifested in training and development.

> A maturing security master plan – a living, adaptive, business-friendly program that is implemented in phases to create and capture value for our companies – serves us no matter what challenges come our way.

Security certifications are important because they are the competency benchmark, helping everyone speak the language of security standards that apply to private industry and government alike.

Training is a bold step that all of us should be taking.

So in short, there are four criteria for integrating security into our operations:

• The application of global standards across the board for an integrated approach;

• The commitment of leadership to security as a matter of policy, and as the foundation of a security culture;

• Training and certification, and

• Applying security to all activities as part of operational excellence.

All of these measures take the enterprise from the reactive level of enforcement to the proactive level of engagement, conveying the leanness and agility to protect assets and maximize functionality, and by extension, profits.

Ladies and gentlemen, risk is inevitable. Thus it is incumbent on us to develop mitigating tools and strategies specific to the organization for a quick, effective response.

A maturing security master plan – a living, adaptive, business-friendly program that is implemented in phases to create and capture value for our companies – serves us no matter what challenges come our way.

Each cycle can bring us to a new level of complexity in preparedness and continuity management – and therefore to a higher level of leadership.

And that leadership is especially important for the Middle East.

The eyes of the world are on our region, ladies and gentlemen. As economic growth shifts toward Asia, we matter; given our importance to world energy, we matter. Our needed, and expected, contributions to the global economy hinge on our ability to manage the challenges of protecting our assets.

Today, I hope that all of us will seize this chance to develop enterprises with the ability to withstand tumultuous events while delivering sustainable growth and social opportunity.

Thank you for your kind attention."

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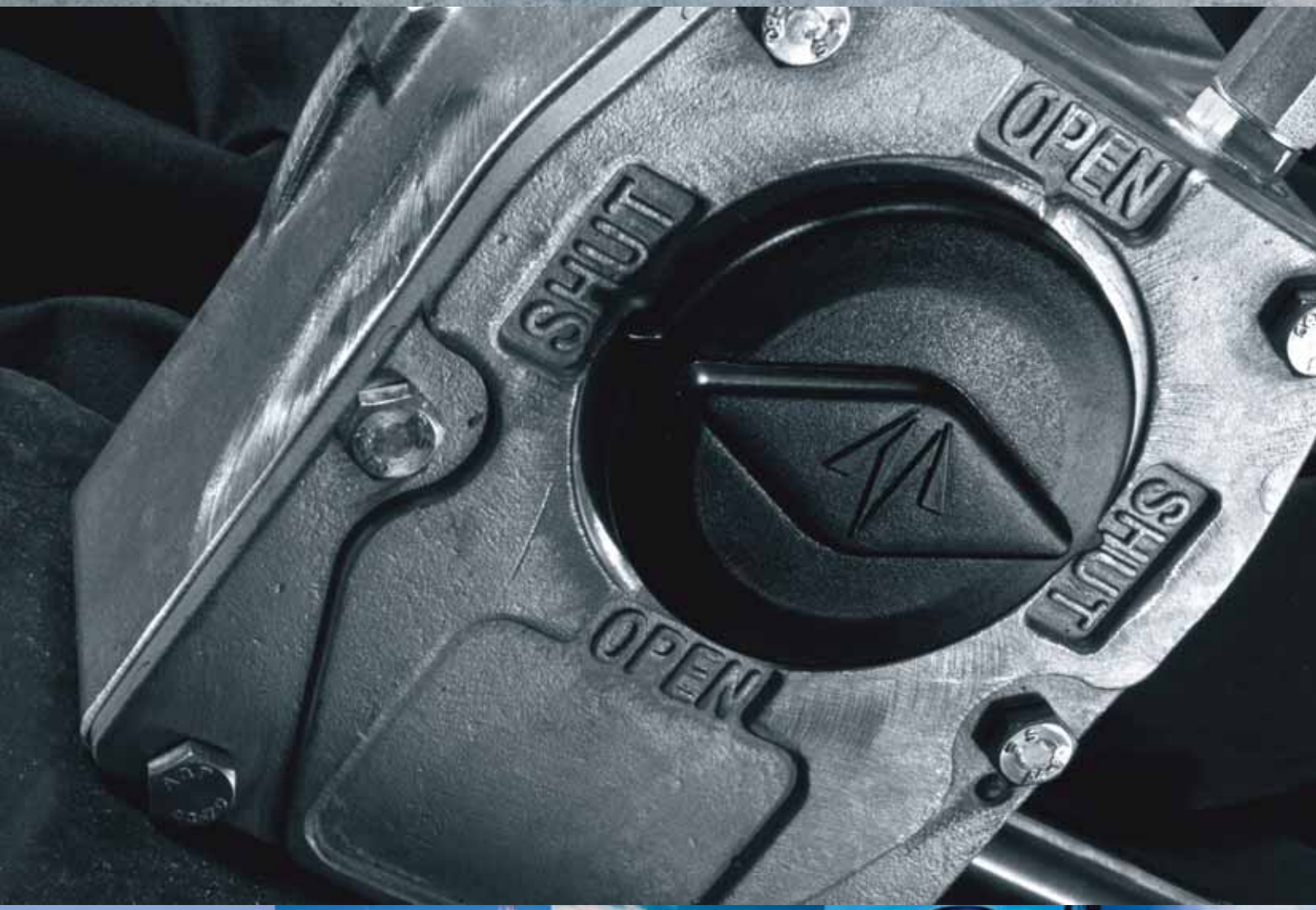

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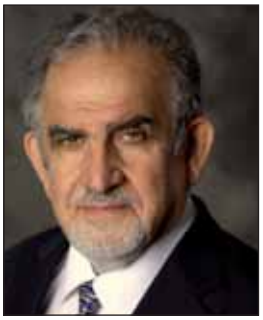
Q&A with the Head of USC Petroleum Engineering Program

By Karam S. Al-Yateem and Ahmad Al-Kudmani.



Dr Iraj Ershaghi.

Dr Iraj Ershaghi is the Omar B. Milligan Professor and director of the Petroleum Engineering Program at the Viterbi School of Engineering, University of Southern California. He is also serving as executive director of CiSoft (USC-Chevron Center of Excellence for Interactive Smart Oilfield Technologies).

The following interview was facilitated by Karam S. Al-Yateem and Ahmad Al-Kudmani, the Saudi Aramco employees who were instrumental in the establishment of the University of Southern California (USC) – Alumni Club of Arabia (ACA). The facilitators would like to thank Stephen Brundage of PRD for his insightful feedback.

Saudi Arabia Oil & Gas: Professor, tell us about the current industry perception of "smart" oilfield technologies.

Dr Ershaghi: A few years ago, we used to call the evolution of the technology "digital oil fields of the future" (DOFF). Now the future is here, and the use of "smart" and integrated oilfield technologies is a part of operations in many large international and national companies, and in small companies as well. I even see conservative operators who had been sitting on the sidelines adopting aspects of these technologies now. The biggest problem many face is the shortage of subject matter experts who can function in a collaborative environment. Rapid training at all levels is still an issue considering that the majority of entry-level engineers are not trained in the use of "smart" oilfield technologies.

Saudi Arabia Oil & Gas: What technologies have evolved in this arena of intelligent oilfield operations?

Dr Ershaghi: Besides the completion of "smart" wells, development of affordable sensors and remotely operated control valves, major progress has been made in "smart" data management and data mining tools, performance-based modeling, and increased use of AI in decision-support systems. Collaboration rooms have also been established as the first step to promoting and enhancing team-based decision-making.

Saudi Arabia Oil & Gas: What are the gaps in the use of these technologies?

Dr Ershaghi: The major gaps in many areas include the limitations of existing data integration, the expense of multiphase metering for individual wells, limitations in technology for real-time down-hole sensors and the costs associated with them, measurement tools and man-machine interaction.

Saudi Arabia Oil & Gas: What is SPE doing in promoting the concepts?

Dr Ershaghi: Besides a number of global forums and workshops, SPE conducts two major conferences related to "smart" oil fields. The Intelligent Energy

> Petroleum engineers cannot continue using 19th century technologies when other options can help visualize the complex systems they manage from reservoir to well bore to surface facilities.

Conference in Utrecht, Netherlands, in March will focus on the scientific progress and includes case studies and industry panels. There is also a Digital Energy Conference, sponsored by the SPE Gulf Coast Section, in Houston, Texas, where more case studies and practical solutions will be discussed. SPE now offers two short courses related to the topic. Last August we conducted an SPE-sponsored colloquium for Petroleum Engineering department heads to discuss solutions for introducing these concepts in the undergraduate PTE curriculum.

Saudi Arabia Oil & Gas: How did USC get involved with its graduate program on the subject?

Dr Ershaghi: The educational program related to "smart" oilfield technologies was part of the effort to establish a research center focusing on these issues. CiSoft also established a hub for training a new breed of hub center of excellence where students with an Information Technology (IT) background could attend an orientation about oil and gas upstream operations, and PTE students could learn about IT opportunities to transform the industry. Since 2004, for professionals who could not attend as full-time students, we have offered four courses related to these areas via our Technology Enhanced Distance Education Network (http://Mapp.usc.edu). Thanks to the support of Chevron, we are the only school offering this educational opportunity to industry professionals worldwide.

Saudi Arabia Oil & Gas: What would be some recommendations you can make to the new engineers joining the industry?

Dr Ershaghi: This is the age of information and knowledge management. The new generation of engineers joining the oil industry is expected to do better than previous generations. The industry and the world expect better recovery factors from the existing and newly discovered fields. They expect assiduous safeguarding of workers and operating environment. Information technology has transformed other industries including health care, banking, aerospace, and national defense. Petroleum engineers cannot continue using 19th century technologies when other options can help visualize the complex systems they manage from reservoir to well bore to surface facilities. They now have the opportunity to increase

> "...let us not forget that exploring for by-passed hydrocarbons and energizing existing and even abandoned oilfields also offers great potential for sustaining production if we focus on increasing the recovery factor using advanced monitoring technologies."

the efficiency of resource recovery, reduce operating costs, and minimize well failures and work-related incidents by making intelligent decisions that consider all consequences and interactivities among asset components.

Saudi Arabia Oil & Gas: What can be done to make managers enthused about the use of these technologies?

Dr Ershaghi: In my experience, the value proposition is still not clearly articulated across the industry. There are many case studies that can be shared to make managers aware of how other companies take advantage of these concepts. The companies that have seen value are investing in these technologies to reduce time on data-to-decision cycles, identify onset of failures, and realize opportunities in faster and more reliable production enhancement. They now have the tools to generate better operational and strategic decisions by enabling smart search, meta-analysis and predictive analytics. These decision-making processes are usually under three levels of control loops, each one nested within the other. The smallest loop is for fast, reactive decision making. Using the same sensory data, the mid-level controls apply a higher level of smart feedback controls and proactive monitoring. Strategic decisions are made with long-range understanding of the sensory data and decisions that can show their impact over a longer period of time.

Saudi Arabia Oil & Gas: In your view, who are the biggest players in the intelligent field arena and why? From an expert point of view, noting the generation gap in the oil and gas industry, can you provide recommendations to the major IOCs and NOCs to sustain and further develop our industry to remain the most reliable source of energy to the world?

Dr Ershaghi: To your first question I would name the IOC's early adopters: Statoil, BP, Chevron, Shell and later ExxonMobil. Saudi Aramco certainly leads the way among the NOCs, but national companies in Oman, Brazil, Kuwait, and Malaysia are also moving ahead.

> Exploration to discover new hydrocarbon resources onshore and offshore is expensive and, in many cases, requires and results in development under difficult geologic and operating environments.

In the management of offshore assets, drilling and monitoring expensive multilaterals, these companies have seen enormous value in remote control and operations. Many technologies developed for offshore are now finding applications in onshore fields.

As for sustaining production, the focus is clear. Exploration to discover new hydrocarbon resources onshore and offshore is expensive and, in many cases, requires and results in development under difficult geologic and operating environments. While this effort should continue into new frontiers, let us not forget that exploring for by-passed hydrocarbons and energizing existing and even abandoned oilfields also offers great potential for sustaining production if we focus on increasing the recovery factor using advanced monitoring technologies. Yes, it will require investment for drilling and completing newer and "smarter" wells, it will require smart monitoring of subsurface fluid distribution and reservoir management, but at least we know the hydrocarbon is there. This really requires a universal industry declaration that, given the prevailing economics, the life of oil fields must be stretched. Oilfield abandonment should become a decision for future generations of engineers with better technologies to go after remaining hydrocarbon molecules.

Saudi Arabia Oil & Gas: USC graduated many students from Middle East and North Africa (MENA), many of whom specialized in petroleum engineering. You have had a hand in developing many of these Trojans. In all honesty, is there a competency in which new MENA students most commonly require development? Please elaborate so we can give them an opportunity to work on it prior to attending. Likewise, has there been an area where they stand out compared to their colleagues?

Dr Ershaghi: Over the last four decades that I have taught at USC, I have had the pleasure of working with many students from MENA countries including those from Saudi Arabia, Iran, Oman, UAE, Kuwait Libya, Nigeria, Algeria, Tunisia, Egypt, Qatar and Somalia. They all come from a disciplined family environment.

They are courteous toward their professors and intent on learning. It has certainly been a matter of pride for us that many of these graduates, after returning home, have achieved professional eminence in their countries and in SPE. These days, a very important component of getting professional education in engineering fields is learning the art of teamwork and collaborative decision-making. In the past, with some exceptions, participation of MENA students in team projects was limited by their choice to group studies from their respective countries. In recent years, especially since we started the smart oilfield technology program at USC, we have included in every course the opportunity for group projects. To really get the best of these experiences, I would like to see students from these countries be conditioned and encouraged to participate in group projects with other professional students from the U.S., China, India and South American countries. These networking and collaboration opportunities also provide training in distributed decision-making for solving global petroleum engineering problems. A head start conditioning effort for such training by sponsoring agencies and companies before MENA students attend USC can certainly smooth and accelerate the learning process here.

Saudi Arabia Oil & Gas: What other new technologies is USC pursuing and what are the potential benefits?

Dr Ershaghi: The range of some research areas pursued at CiSoft is reflected in the publication list on the website http://cisoft.usc.edu/publications/. They include immersive visualization, new developments in type II fuzzy logic, semantic web technologies, signal processing, integrated asset modeling and sensors, and sensor nets. Some focus areas include a futuristic look at how oil fields will be run a decade from now. For current, ongoing research, because of the proprietary nature of our work, we do not discuss details in public before technologies and work processes are developed and protected via patenting or copyrighting.

Biographies

Karam S. Al-Yateem holds an MSc degree from University of Southern California (USC) in Petroleum Engineering: Smart Oilfield Technologies and Management. He earned his Bachelor Degree in PE from KFUPM. Karam has a passion for bringing new technologies for implementation consideration that are associated with production gain, operation optimization and cost avoidance. He has taken several assignments in a number of onshore and offshore field locations during his career with Saudi Aramco. He has worked as a reservoir engineer, field engineer, testing engineer and production engineer in Safaniya field. He is the recipient of the 2008 SPE's International Young Member Outstanding Service Award. Karam is an active SPE member and currently serves as a member in the YP task force of Production & Operation, as executive board member of Saudi Arabia Section of SPE and as board member in Saudi Oil & Gas and Brazil Oil & Gas. Karam is also an executive board member of USC Alumni Club of Arabia.

Ahmad Al-Kudmani, being a USC Trojan now for nearly 14 years and a Saudi 'Aramcon' for 15, sees many similarities when it comes to excellence between these two distinguished institutions. He graduated with a BS in Mechanical (Petroleum) Engineering and a Minor in Political Science in 2002. Subsequently, he returned to Saudi Aramco assigned as a plant engineer in the Sea Water Injection Department under the Upstream Business Line. Through the years, he has assumed various professional and supervisory roles in the Engineering, HSE and Operations Divisions within the department, in addition to being part of the largest expansion project to the sea water treatment plant at Qurayyah. More recently, he has been assigned to Corporate Planning on Strategy Development & Corporate Decision Making.

First Commercial Single-Diameter 8 x 9-5/8 in. Solid Expandable Openhole Clad Eliminates Tapering and Isolates Problem Section

By Mark van de Velden, SWE Technology Petroleum Development Oman; Greg Noel and Markus Kaschke, Enventure Global Technology, LLC.

Abstract

The solid expandable tubular system brought about a significant step change in downhole architecture by instituting a technology that reduces wellbore tapering and conserves precious hole size. The single-diameter solid expandable system takes that technology to another level by eliminating the tapering effect and preserving hole size. Although the idea of the single-diameter approach has been in development for years, the concept became a reality with the installation of an openhole cladding system in the Middle East.

An operator used an 8 x 9-5/8 in. single-diameter openhole clad to isolate a troublesome shale section between ~1,500 and 1,650 ft (~456 and 503m) in a large field in the north of Oman. Previous attempts to mitigate this area with cement reinforced slotted expandables proved unreliable. Setting regular casing in this section would compromise hole size, hinder well economics, and reduce production. The single diameter solid expandable system provided a post-expansion inside diameter (ID) of 8.60 in. This pass-through retained an ID large enough to run the same 8-1/2 in. BHA as previously used for subsequent drilling. After placement and expansion of the single-diameter openhole clad, an 8-1/2 in. BHA was deployed to further well construction operations with adequate hole size.

This paper will describe the first installation, including evaluation and operational considerations as well as the results affirming the technology's ability to isolate problem areas without sacrificing hole size. In addition, the paper will discuss the development of the technology and explain the potential to mitigate a variety of problems and conditions.

Drilling Objectives

Wells in this field face a consistently troubling formation. The operator of this project needed to isolate the problem section, but could not afford to lose the critical ID it needed to run the tools and technology that would move the drilling program forward. Initial attempts to use cement reinforced

> The rate and amount of corrosion caused by dissolved carbon dioxide is dependent on the oxygen content, the salts dissolved in the water, temperatures and fluid velocities.

slotted expandables proved unreliable. The objectives as confronted required a two-fold solution – isolate the problem and maximize ID.

Geological Challenges

Reservoir facies in this field are in shallow-shelf carbonates of the Middle Cretaceous Mishrif and Mauddud formations. Interparticle porosity formed in the Mishrif as sand aprons of lithoclast and skeletal grainstones surrounding fault-block islands, and less commonly in the Mauddud as biostromes of rudist packstones. Moldic porosity after fine rudist debris is more common than interparticle porosity and occurs in thicker stratigraphic units, interpreted to have formed locally in meteoric-water lenses of islands, and regionally during subaerial exposure associated with sea level lows.[1] These types of conditions exemplify an exceptionally complex geology interspersed with multiple small oil deposits, each with unique geological structures and each requiring a new approach.[2]

Operational Considerations

The drilling environment consisted mainly of sandstone with multiple interbedded shale sections. One particular section, the deepest of the interbedded shale, tended to swell and was very reactive to water, which can lead to the drillstring becoming stuck when water is passed by. To mitigate the potential for swelling, this section was drilled with inhibited water. The ideal solution to preventing swelling would consist of drilling with oil-based mud, but this approach ran the risk of contaminating shallow aquifers.

To compound the challenge, a carbonate formation below this section is prone to losses. If the troublesome shale section and the formation below were drilled together and a loss zone was encountered, the well could fill with water. This brackish water would cause severe reaction in the shale section and could collapse the hole. The section needed to be isolated but setting conventional casing would reduce the hole size and jeopardize the well economics. In the past, curing losses in the carbonate formation were time consuming and encountering another fault would require abandoning the well starting over.

The wells in this project are the soundest economically with an 8-1/2 in. hole followed by 6-1/4 in. hole into the reservoir. Scaling up the casing design to set a shoe below the troublesome shale would hinder economic viability. These factors led the operator to

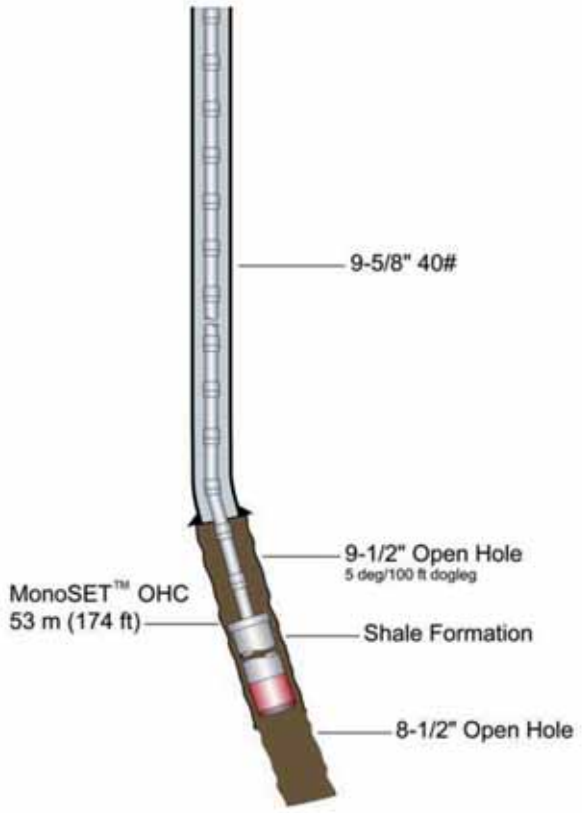


Figure 1 – Single-diameter openhole clad isolates troublesome shale section.

select Enventure's MonoSET® openhole clad (OHC) to isolate the shale without reducing the wellbore ID.

Installing a Solution

The drilling plan landed 9-5/8 in. casing at ~1,280 ft (390m) and cemented it in place back to surface. A bottomhole assembly (BHA) with a 9-1/2 in. bi-center bit drilled to a TD of ~1,660 ft (~505m) and 43° angle. Four logging runs, using four- and six-arm caliper tools, identified two tight spots. Removal of the tight spots was accomplished with a 9-1/2 in. PDC reamer and a 12-1/4 in. roller-cone reamer. The operator took extra care to facilitate proper hole size and optimum wellbore conditions prior to running the single-diameter system. This systematic precaution helped ensure a smooth installation and an uncomplicated application.

The 8 x 9-5/8 in. OHC was run to a depth of ~1,650 ft (~503m) in three hours (Figure 1). This OHC is a single-diameter solid expandable tubular system designed to maintain the hole size of the previous casing string. In contrast to a conventional solid expandable system that reduces the tapering effect, the single-diameter system eliminates tapering.

Using a hydraulic-mechanical expansion assembly, expansion was initiated with 3,000 psi. The 150-foot (47m) OHC was expanded per plan with all parameters in the expected range. An 8-1/2 in. drilling BHA was picked up and run through the expanded liner, which confirmed the expanded ID and the placement of the liner were both correct. After an 8-1/2 in. openhole section was drilled to 2,641 ft (805m), a 7 in. liner run through the OHC and cemented back to the surface. The OHC stabilized the trouble section, facilitating an efficient wellbore construction operation without compromising hole size. The operator remained on well design and drilled a 6-1/8 in. open hole to ~4,600 ft (~1,400m) as planned.

The successful installation of this first single-diameter solution resulted in the application of a second OHC by the same operator in a different well. The subsequent application took place in similar conditions and parameters. An 8 x 9-5/8 in. MonoSET OHC a~141 ft (~43m) in length covered the trouble zones and enabled the 7-inch casing to be run to the planned depth and cemented in place. Both OHC systems kept the drilling program and the original well economics intact and on target.

Figure 2 – Running sequence for the single-diameter openhole clad system.

Developing the Single-Diameter Technology

The path to actualizing the single-diameter system took a circuitous route that included amended theoretical approaches (ex. one-trip system vs. two-trip system), numerous design iterations of tool components and subsystems, and several field-appraisal tests. An intentional focus on developing the system spanned a decade that ran parallel with the maturation of conventional solid expandable tubulars. The evolving technology, the broadening application spectrum, and the commercial deployment of the OHC in the Middle East illustrate the results of a successful strategy to provide the enabling tools and processes to "lower lifting cost and maximize recovery".

The single-diameter design concept itself was closely controlled and incorporated multi-disciplinary processes with a team that included drilling experts, engineers, designers, and end users. To develop a reliable tool for a myriad of conditions and applications, modular components proved to be the most practical plan for construction as it provided easier customization for specific applications, simplicity in overall design, and quick assembly of tools. The design team was able to leverage a sound foundation of solid expandable tubular knowledge that included an advanced understanding of pipe metallurgy, properties and the effects of stresses and strains endured during the expansion process.

Proving the Concept

The proof-of–concept, single-diameter well was completed in South Texas by Shell Exploration and Production Company (SEPCO) in July 2002. Although this project provided a multitude of technical learnings and the well was commercially completed, the actual number of trips required to construct the single-diameter sections along with difficulties in zonal isolation, made this system configuration impractical for broad-based field use in that oilfield market. However, the basic principles to construct a single-diameter well were proven.[3]

From this proof-of-concept well a more refined perception and base operational overview emerged that identified design elements that needed refining. The result was a multifunctional tool that would integrate all sub-systems and assure self-contained contingencies. This direction represented a marked divergence from any conventional solid expandable tubular tool configurations or design. A tool string prototype was manufactured and tested in a live well in late 2004.

Continued refinements and enhancements led to a field appraisal test (FAT) in 2007. For the FAT, the string tested consisted of six different tools each subjected to a vigorous testing program. Each tool was placed in a right-hand torque test to 10K ft-lbs, the maximum

> "In formations such as hard rock, the single-diameter system could be used in an openhole configuration to clad over problematic formations in an otherwise stable section."

torque loading for the casing connections. Testing to this torque capacity, which exceeds the allowable torque for the liner, ensured that the tools could be rotated to wash down in the hole while running. The tool string was tested in the horizontal position with sand-laden fluid for flow testing and fluid cutting. In addition to horizontal, it was also run in the vertical position in oil- and water-based mud.

Following successful surface testing of the tools, the downhole portion of the FAT was initiated. As part of the construction of a dedicated test well, Enventure was able to drill deeper than the prescribed well requirements and install any number of liners as part of the test program. The test included the placement of three consecutive liners each with the same final ID of 10.4 inches. Each liner was installed using a slightly different tool configuration which emphasized the modularity of the system. The first liner was installed and included the expansion of a larger "bell" section at the bottom to act as a receptacle for the second liner. The second and third liners did not include the bell section. This required the overlap section in the second liner to be expanded along with the third liner. In all, a total of approximately 1,750 ft of single-diameter liners were installed in a hole that built to a final angle of ~55°.

The FAT provided the environment to affirm system performance and establish real results. The objective to simulate field parameters, such as high-angle bending forces, an oil-based mud environment, while confirming the functionality of the tools and the ability to cement through the single-diameter tools were exceeded by the test.[4]

The FAT also indicated that although it was possible to install single-diameter liners in a single trip, the complexity of the operation would need to be reduced for it to become a common practice. The natural progression is to break the process down into more simple pieces like the single-diameter OHC and shoe extension. Eventually, through experience and refinement, the smaller pieces will come back together in the construction of a true single diameter well

State of the Technology

The current operating parameters of the single-diameter openhole clad system provide an 8-1/2 in. pass through below the 9-5/8 in. casing. This system can be expanded against the formation, eliminating the need for cementing and the need to tie-back into base casing. The preservation of hole size can be the length of a single joint to or over 1,000 ft. The running sequence of the single-diameter openhole clad system is similar to conventional solid expandable tubular systems (Figure 2).

1. Drill thru problem zone
2. Run liner and inner-string
3. Expand liner across problem zone
   - Activate anchor

> The successful installation of the previously discussed single-diameter systems strategically mitigated trouble zones in the formation by isolating targeted sections of the wellbore without anchoring back into the previous casing.

- Expand lower seals
- Initiate mechanical expansion

4. Recover tools and operational pipe
5. Drill ahead

Identifying the Potential

The use of single-diameter expandable casing technology has the field-proven potential of significantly reducing a project's drilling and completion cost structure. These savings are realized by reducing drilling risk and resultant trouble time by successively isolating problem lithology and/or underpressured zones while preserving a single-diameter wellbore.

Reductions, in turn, result in zero compromise of the completion objectives and afford much greater completion flexibility and potentially lower the life of well costs with improved completion design and required interventions. Gulf of Mexico operators, which often encounter severe lost circulation zones at shallow depths, are watching the technology development in hopes of expanding long drilling liners to isolate these under-pressured zones and then later case off the expanded liner and problem zones. Other operators see the great potential of installing several uphole single-diameter drilling liners to allow a fullbore completion at total depth (TD).

The technology also has the proven, simulated and engineered potential of significantly increasing the lateral reach of many extended reach wellbores.[5] Successive installation of expandable, single-diameter wellbores is possible, which primarily reduces the friction/drag forces that can limit lateral reach, again, while preserving a single-diameter wellbore as deep as required. In addition, this application affords higher weight-on-bit at comparable depths versus conventional drilling technology. This extended lateral reach results in increased reservoir contact that can often result in increased production per well.

Extended-reach laterals can be cased with successive liners that preserve ID. Using shorter lengths of casing that maintain a constant ID prevents friction and drag increases. A study done for a major North Sea operator showed that single diameter systems could extend the current ERD envelop up to 50%.[6] The study concluded that added reach achieved by reduced friction could lower well count, raise well production, increase reservoir contact, increase reserve access, improve capital efficiency and lower field development costs. Proven drilling performance and additional cost studies indicate that expenditures reflected in the same North Sea study area could be reduced 30 to 50% of the current drilling cost with the application of solid

expandable tubulars and constant-diameter technology.

More production from fewer wells can ultimately lower required field well counts with an improved drilling cost structure profile. In select offshore applications, this technology can in turn result in lower platform installation requirements without reserve reductions or potentially increased reserves by tapping flank or step-out reserves. In many subsea applications, the technology can result in lower subsea templates, flowlines, pipelines and production center requirements. The technology also offers enhanced development flexibility with minimum economics by allowing the deferral of high capital cost outlays with improved development phasing. In subsea applications that include seabed geohazards, such as escarpments or Arctic iceberg risks, the reduced subsea infrastructure requirements further mitigates project risk and improves field economic returns.

In modeled worldwide offshore and subsea developments, the system greatly reduced observed and/or forecast drilling risks and trouble time. The modeling indicated that the prudent application of successive single-diameter expanded liners has proven to increase lateral reach potential by 25 to 50% and in select applications, these results exceed the current industry lateral reach record by over 35%. In formations such as hard rock, the single-diameter system could be used in an openhole configuration to clad over problematic formations in an otherwise stable section.

Wellbore diameter is maintained and the operator forgoes the need and cost to cover an entire zone. Another obvious benefit 4 M. van de Velden, G. Noel, M. Kaschke AADE-11-NTCE-57 of this technology suite is its ability to facilitate a shoe extension. Multiple casing points can be made up or initially attained without losing hole size.

Conclusion

The successful installation of the previously discussed single-diameter systems strategically mitigated trouble zones in the formation by isolating targeted sections of the wellbore without anchoring back into the previous casing. Proving the validity of the equipment, the process, and the potential opens the possibility of diverse applications with far-reaching benefits. As with conventional solid expandable tubulars, the more the technology is utilized the greater the benefits realized. These benefits include decreasing drilling cost structure and/or reducing drilling risk and trouble time, improving field development economics, accessing greater reserves, increasing production per wellbore, and potentially creating a smaller field development footprint These systems no doubt will play a significant role in the current climate of accessing reserves that not only affect the bottom line but save time and resources as well.

Acknowledgments

The authors would like to thank the Sultanate of Oman Ministry of Oil & Gas and the management of PDO and Enventure. In addition, we express our thanks and sincere appreciation to our colleagues, all of the technical experts, and the service companies who made this project possible.

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Corrosion Control Planning is Critical For Extending Life of Injection Wells

By Oscar Zapata, Engineering Manager, Duoline® Technologies.

As early as 1875, oil operators concluded that water injection could be used as an effective method for driving oil from within a formation. Other means of recovery have since then been developed. After years of trial and error, however, it has become apparent that water – either from natural geothermal or surface sources – is the most economical means of secondary recovery.

Sources For Injector Water

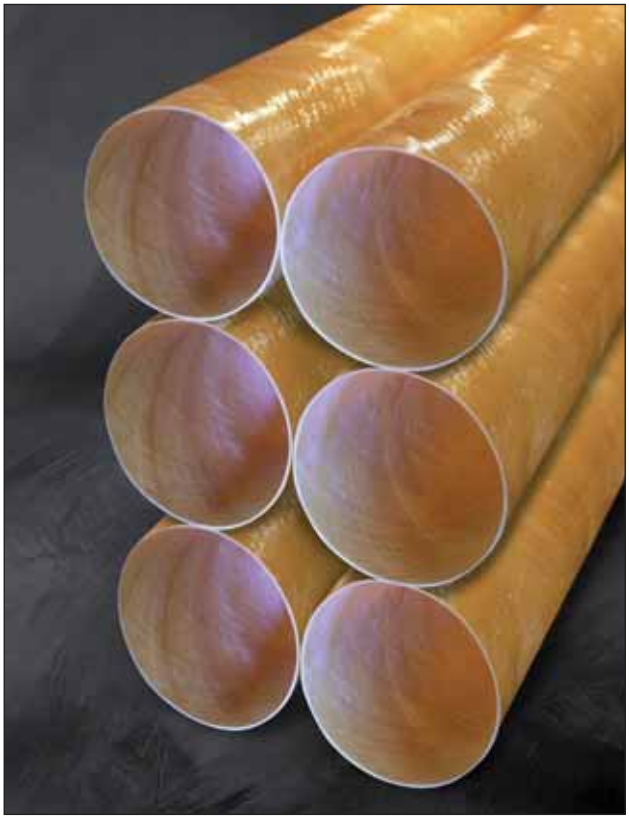
The following sources of water are typically used for recovery of oil:

• Produced water: often used as an injection fluid. Produced water is a term used in the oil industry to describe water produced along with oil and gas. If the volumes of water being produced are not sufficient, additional "make-up" water must be provided. Mixing waters from different sources exacerbates the risk of corrosion.

• Seawater: the most convenient source for offshore production facilities. At times it may be pumped onshore for use in land fields.

• Aquifer water: from water-bearing formations other than the oil reservoir. Aquifer water has the advantage of purity where available.

Failure of a pipeline.



Duoline liners.

Problems Associated With Water Injection

Despite the many benefits gained by using water, the quality of the injection water is continuously blamed for failures in the water injection system from the seawater intake facilities to the well bore.

Corrosive damage to the pipe from these waters results in significant costs to the E&P industry. For example: at times repairing wells has resulted in prolonged work-overs and eventual shutdown injection facilities; and can also affect a company's capability to push water into the reservoir to maintain its pressure.

Injector System Corrosion

The type of corrosion caused by reservoir water depends on the chemical composition of that fluid. These waters can be composed of a wide range of chemicals including strongly acidic waters containing sulphur and halogen acids which actively corrode most common alloys.

Installing Duoline liners.

> The rate and amount of corrosion caused by dissolved carbon dioxide is dependent on the oxygen content, the salts dissolved in the water, temperatures and fluid velocities.

The velocity of injection fluid can also affect the rate of corrosion. As velocity increases, the transport of oxygen to the surface becomes faster, so the corrosion rate increases. Injection velocity can also cause scouring of corrosion products, thus removing the protective film.

Oxygen: The Greatest Concern

The gas that causes real corrosive consequence in this environment is oxygen. Although the solubility of oxygen decreases to a minimum as the temperature rises near 100°C, it is very important to minimize CO_2 contact with water. CO_2 corrosion attack increases with increase in oxygen concentration, the organic acid by-product is referred to as carbonic acid (H_2CO_3).

Carbon-Dioxide Corrosion: Still of Concern

Carbon dioxide in water can contribute to corrosion of steel, but at equal concentrations it is much less corrosive than oxygen. The rate and amount of corrosion caused by dissolved carbon dioxide is dependent on the oxygen content, the salts dissolved in the water, temperatures and fluid velocities. Water containing both dissolved oxygen and carbon dioxide is more corrosive to steel than water that contains only an equal concentration of one of these gases.

Hydrogen Sulfide Corrosion

Hydrogen sulfide is often present in oil field production brines that are subsequently disposed by well injection. This practice has resulted in instances of severe corrosion in injection tubing, especially when brines become contaminated with oxygen. Corrosion rate also increases in water containing hydrogen sulfide and is influenced by the presence of dissolved salts and carbon dioxide.

Chlorides: Causes Stress Corrosion Cracking

The presence of chlorides in the well fluids attack pipe material and is influenced greatly by the temperature, chloride concentration and stresses in the metal. The presence of oxygen and low pH value accelerates the attack on the metal.

Elemental Sulfur Corrosion:

Elemental sulfur will be present in some reservoir fluids and is a very strong oxidant. It mixes with the water in the fluid and forms sulfuric acid and reacts to form

sulfides. Corrosion due to elemental sulfur increases with temperature.

Fighting Corrosion in the Oil & Gas industry

Fighting corrosion continues to be a nightmare for many oil field staff. While there are many methods to prevent corrosion these are the three most common:

• Change the material of construction for the specific application.
• Reduce the intensity of corrosive attack by modifications in corrosive media.
• Create a barrier layer between the material and media to avoid the direct contact.

Corrosion Prevention: The Reality

Mitigating the effects of corrosion found in injection wells harsh environment can reduce expenses, lost revenue, and risks to safety and the environment. Yet, before making any changes to prevent corrosion remember there may be additional cost. It is more important to think in terms of life cycle costing, which may show a longer equipment life and lower maintenance cost in spite of high initial cost. Before any change is made a detailed study of the injector process and operating conditions should to be carried out by a professional corrosion engineer.

Fiberglass Liners Provide Effective Solution in Harsh Environments

There are effective ways to prevent corrosion in order to extend the life of the tubular. Operators have used a variety of coatings and liners including internal fiberglass lining.

Many major oil companies have found that fiberglass liners offer an ideal solution to prevent damage to pipe. This is due to fiberglass being strong and light weight for easy moving, as well as the material's effectiveness in providing a long-term corrosion prevention solution.

The company offers a variety of liner selections that match material performance to specific application needs. The unique process of inserting a rigid plastic or GRE composite (Glass Reinforced Epoxy) liner sleeve inside the pipe eliminates the "holiday" potential.

Duoline® fiberglass liners are cured by applying internal heat to a hollow mandrel. This ensures that encapsulated air pockets do not occur on the liner's body-wall – a major differentiation from liners produced using a thermal cure cycle which cures the outer diameter first and increases the potential for product failure by encapsulating air pockets on the liner's body-wall. This benefit, combined with the high hoop strength of the company's GRE liners provides the most resilient available lining system for high-pressure gas service or water systems with high CO_2 or H_2S content.

Another important consideration for any corrosion resistant piping system is protection of the connection area, which is the strength of the liner process.

Most coated tubing corrosion failures originate in the connection area and this is why the technology employs a reinforced elastomeric corrosion barrier ring (CBR), which is compressed between the liners in the connection make-up process. This compressed CBR is held in place by the liner, and prevents passing fluids from causing the all-too-common coupling failure. The technology also employs a metal wire reinforced nitrile elastomer ring for API connections and a Teflon glass filled corrosion barrier ring for premium gas tight connections.

Optimization of Cableless Technologies to Obtain Reservoir Pressure and Temperature for Real-time Monitoring

By Karam S. Al Yateem, Khalid I. Al Omaireen; SPE, Saudi Aramco.

This paper was prepared for presentation at the SPE Intelligent Energy International held in Utrecht, The Netherlands, 27–29 March 2012.

Abstract

Acquiring downhole pressure data is essential for successful reservoir management; it paints a picture depicting the reservoir's behavior. Presently, the intelligent field concept has matured to such an extent over the last decade that several major oil operators in the world now have fields where intelligent technologies have been deployed on a large scale. Saudi Aramco is one of the pioneering oil & gas operating companies, which have put huge investment to transform its oil fields into intelligent fields with expectation to maximize the hydrocarbon recovery, simplify operations and minimize human interaction hence enhancing safety. As the concept of intelligent field has matured, more and more operators are embracing this new concept with expectations for higher recovery factors. Permanent Downhole Monitoring Systems (PDHMS) is one such intelligent field component which provides continuous monitoring of reservoir pressure. PDHMS has become an indispensable tool for reservoir surveillance particularly for offshore fields in which gauge deployed pressure and temperature surveys are always affected by external factors such as the weather. PDHMS's are installed to eliminate wire-line unit and/or expensive barge visits. Another obvious advantage is that the system can turn any shut-in time as an opportunity for both pressure survey and well testing, thus largely reducing the non-productive time of a producer and significantly improving the reservoir surveillance frequency.

The installations of PDHMS consist of two electronic gauges installed normally at the end of tubing with a distance of some 200 ft to 300 ft of true vertical depth (TVD) between the gauges to profile the gradient. These gauges are connected to surface recording and data transmitting equipment through an electrical cable or fiber optics attached to the outside of well tubing. The installation and retrieval of PDHMS, in case of malfunction requires capital investment in the form of rig utilization. Rigless wireline deployed gauges have been considered in the past but with cable running inside the tubing making it containing more disadvantages than advantages. Hence the next progression of this technology was a wireline retrievable gauge without the need for any cable, cableless pressure

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gauge allowing a wireless broadcast of data. These battery operated gauges can be set and left in the hole riglessly for an extended period of time of up to three or more years, depending upon data transmitting frequency. This technology was recently trial tested in one of the Saudi Arabian fields for about a year with promising results. The aim of utilizing such a system was to improve well intervention safety, control cost, and optimize resources. Additionally, like PDHMS, cableless gauges have a huge potential to simplify logistics compared to conventional surveying.They are superior in the fact that they are wireline/slickline deployed. This further opens the opportunity to replace failed PDHMS with cables-gauges in offshore environment in particular to continue monitoring pressure without waiting for a work over rig resources.

Saudi Aramco's strategy is to further revolutionise the use of the technology behind cableless gauges by installing them in selected observation wells at the datum point depth if feasible. With this cableless gauge, only one gauge will be required as compared to the conventional practice of installing two PDHMS gauges. This paper will address old and new methods including conventional wireline survey, well testing, PDHMS and cableless gauges, which are utilized to obtain downhole pressure to establish a tangible comparison between them. The paper also discusses a method to estimate the static bottom-hole pressure (SBHP) through extrapolation to datum empirically.

Introduction

Electromagnetic (EM) waves technology has been widely pioneered for public needs such as biotechnology research, medical applications and all sorts of related telecommunications. The recognition of this technology in the Oil & Gas (O&G) industry provoked an affirmative change. For many years, operators have desired the ability to recover downhole data from downhole without the need for cables, either permanently installed or in the form of temporary wireline. The cableless pressure gauge technology was successfully trial tested as an alternative downhole-monitoring tool in one of Saudi Arabia's offshore fields. This technology is a 3-year battery operated system, hung inside the perspective well production tubing, transmitting pressure data to surface in real time fashion without a direct cable connection in the well. This is achieved through the electromagnetic interference through the steel pipe. It uses tubing/casing steel as the transmission media. Deployment can be always conducted through a standard slickline without the need for a rig or cable or fiber-optic connections compared to other monitoring devices such as PDHMS. Most in-well wireless telemetry system is based on the following[1]:

1. Pressure waves within the product.
2. Acoustic/Sonic waves through the tubing wall.
3. EM communication through the formation.
4. EM communication through the casing and tubing.
5. Coaxial current loop systems.

Previously, to effectively map the pressures of any field and thoroughly investigate the status of any well, a data acquisition of essential data such as pressure and temperature were conducted through well intervention. This technology eliminates this requirement. It is also vital to understand that knowledge of continuous pressure becomes truly beneficial toward the better understanding and the management of the field in real-time fashion. Therefore, it is widely accepted that the primary objective of installing PDHMS is to eliminate wireline unit and/or expensive barge visits for pressure surveys required for reservoir surveillance. Another direct advantage from a PDHMS is that the system can turn any well shut-in time as one opportunity for both pressure survey and well testing, largely reducing the non-productive time of a producer and significantly improving the reservoir surveillance frequency. The installations of PDHMS, however, consist of an electronic measuring gauge placed at significant depth below the ground and connected to recording equipment through an electrical cable or fiber optics attached to the well pipe. Therefore, the application of cableless is intended to potentially further improve well intervention safety and optimize resource utilization. In addition, it provides cost containment competitor to the routine slick-line intervention and a supplement to the PDHMS. The trial test of this technology was conducted over three onshore and offshore wells with different configurations encompassing single and multi-well platforms. The pressure data was continuously transmitted from the bottom hole to surface every three hours with no interruption. Moreover, the data showed good pressure response at different rates exhibiting no rate limitation. Based on the trial assessment; it was obvious the vast benefits that this technology reveals to the industry. It was also estimated that the battery life worst-case scenario could easily last up to three years. The proposed initial stage involved the retro-fitting of through-tubing cableless gauge systems into existing monitoring and production wells in the field, to enable real time reservoir surveillance, optimize the annual barge visits and activities, which as a result will improve the field requirement annual efficiency.

Technology Utilization Progression

The industry is tackling exhilarating problems through the use of technologies from mega-cell reservoir simulation, to implementation of fully integrated intelligent fields, geo-steering, and laser drilling, offering a wide-range of interdisciplinary domains for development and progression[4]. The quest of technological advancement in Saudi Aramco goes across the board and beyond the reasoning of any other national and international oil company. Saudi Aramco has different needs compared to most other companies. Most are using new technologies to increase production, cut costs, and accelerate recovery as much as possible in a drive to maximize value for their shareholders. The above are goals of Saudi Aramco as well with the important exception of accelerating recovery. Saudi Aramco needs to reliably sustain production levels and maximize their recoverable resources. Well intervention technology transformation is recognized as a fundamental core business practice to simplify operation logistics, optimize resources and enhance safety. Undoubtedly, the new technology application is eminently needed to cope-up with the increasing number of wells, field maturity and the new field increments and developments. Specifically, pressure and temperature surveys that usually represents more than 60% of the yearly well intervention and data acquisition requirements of which 80% is completed

Table 1: Measuring downhole pressure technology progression comparison

Item	Electronic	Cable less	PDHMS*
Cost (3 years)	$192,000	$96,000	$450,000
(6 years)	$384,000	$120,000	$450,000
Barge visits in 3 years	12	1	N/A
Operational Complexity	Wireline retrievable	Wireline retrievable	Require a rig
Replacement Flexibility	Require a boat	Require a boat	Require a rig
Application	No limitation	No limitation	Limited

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utilizing jack-up barges and floaters while the remaining is achieved via PDHMS in the case of our offshore field. Therefore it is vital to not only look for an integrated technology deployment but also look for alternatives.

The evolvement of Static Bottom Hole Pressure (SBHP) measurements went through three progressions. Methods of attaining pressure readings old and new are discussed to establish a tangible comparison between these methods, normal survey, PDHMS and cableless gauges; Table 1 exhibits the differences between the subject progressions. Amerada* gauges were utilized with an average of about 20% error of validated data. Amerada also required 10 gauges per well. Electronic gauges were used at a later stage, the introduction of the electronic gauges reduced the error drastically to about 1% by running a single recording gauge per each run instead of 10 in case of Amerada. PDHMS design and data utilization was another progression. This technology utilization was associated with a transformational measure that allows attaining real time data. PDHMS were widely utilized in Saudi Aramco as part of intelligent field activities. Usually two sensors are installed to calculate the gradient and hence estimate the reservoir pressure. PDHMS are installed by rig. If in the case of a failure, a rig has to replace the sensors. PDHMS are also an integral part of artificially lifted wells where pressure is measured through the ESP sensors. In the case of a single gauge, an "extrapolation to datum" empirical study was performed to withdraw the reservoir pressure by extrapolation from a single downhole measurement of pressure acquired using a one PDHMS, one cableless gauge or ESP sensor. *Amerada was created by Geophysical Research Corporation.

SBHP surveys are routine activities conducted by well services vessels using electronic gauges in each well separately. This procedure entails rigging up with safety equipment, lubricator, and pressure gauge. The gauge is then run to roughly 300' above end of tubing (EOT). It stops there for five minutes to record the pressure (gradient stop). The gauge is then lowered even further to approximately 100' above EOT to take the bottom stop reading. The difference between the gradient stop and the bottom is used to generate the gradient for the subject well in psi/ft, which in turn used to extrapolate

Figure 1: Physical appearance of tool prior to installation.

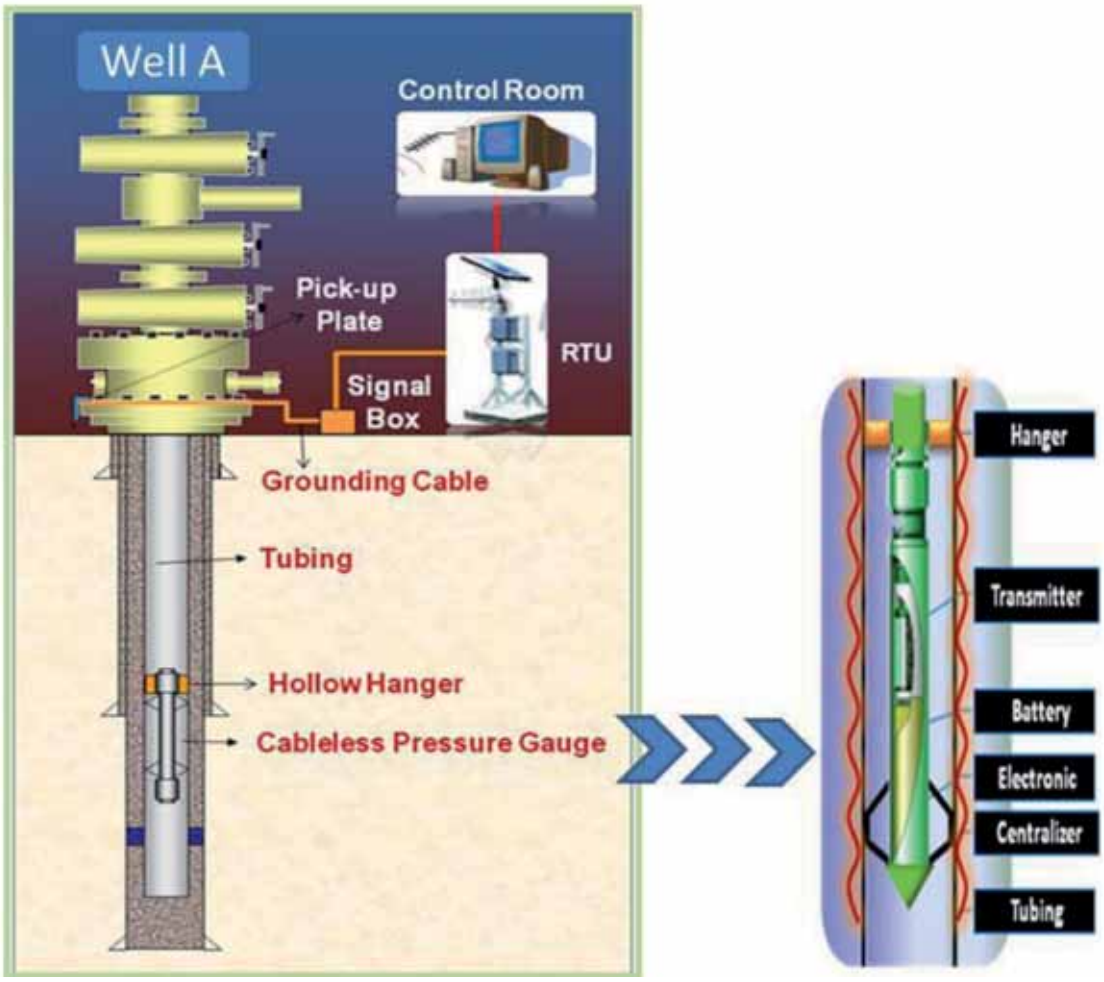

Figure 2: Conceptual drawing exhibiting the major component of the system.

> The cableless pressure gauge is a permanent wireline retrievable gauge with a long-life battery that is hanged safely inside the production tubing.

the bottom stop reading to the middle of perforation depth, commonly referred to as the midpoint. Pressure at midpoint is then referenced to the original oil water contact based upon which either pure oil gradient or pure water gradient is used to extrapolate the midpoint pressure further to the datum depth. Due to the increasing number of wells and installation of PDHMS and other intelligent field equipment, it was time to investigate other methods that can deliver this pressure with the least resources engagement. This and the high rig operations cost to install and replace a PDHMS have inspired the search for alternative technology to improve the operation and overcome obstacles. Refer to table 1 for economic comparison. Costs are rounded up and should be considered as estimates. The following major assumptions are made:

- PDHMS gauge and cable cost is around $350k.
- Installation of PDHMS is about 2 rig days at about $50k/day.
- Each barge visit cost around $16k.
- The three gauge types never fail or break and require no maintenance except battery change for cableless every 3 years at $8k.
- Wells with PDHMS are never worked over during these calculations (eliminating the cost of new cable after WO).
- Pressure surveys are required four times a year as a minimum.

This was another factor to trial test the last evolvement of static bottom hole pressure measurement, the cableless pressure gauge. The cableless gauge also tackles several Health, Safety, Security and Environmental (HSSE) concerns and improves logistics and utilization of company resources. It is deployed riglessly and hence complements PDHMS in the case of malfunctioning. Moreover, through the empirical study, the unit can be deployed at any depth. This telemetry technology package includes a downhole gauge, hanger, surface receiver, surface panel and Supervisory Control and Data Acquisition System (SCADA) communication equipment which make the components almost similar to the conventional PDHMS.

Cableless Pressure Gauge Technology

The cableless pressure gauge is a permanent wireline retrievable gauge with a long-life battery that is hanged safely inside the production tubing. To visualize the appearance of the unit and how it is stationed inside the hole, refer to figures 1 and 2. It transmits pressure and temperature data constantly through sending coded electromagnetic waves. The system transmits low frequency EM waves from downhole

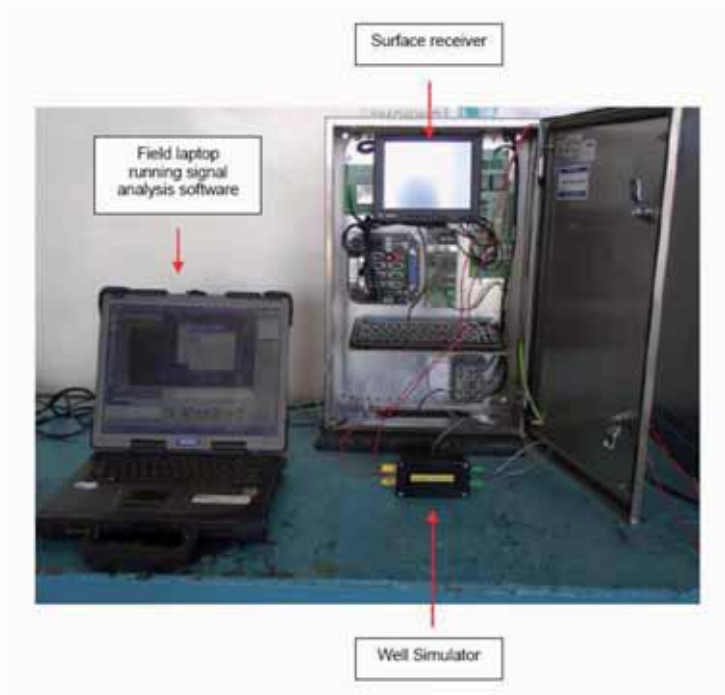

Figure 3: The system transmitting inside 4-1/5‰ tubing.

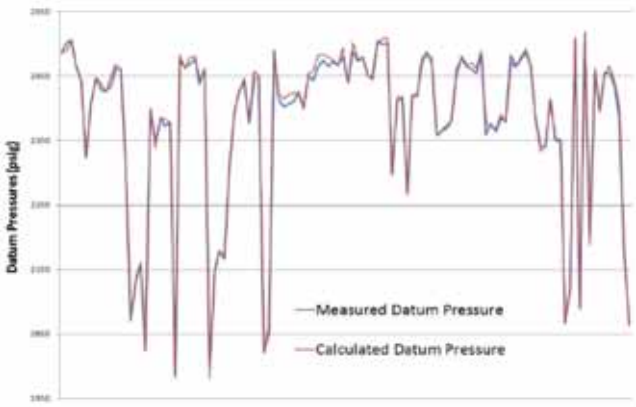

Figure 4: Pressure from different methods overlaid on the same plot.

to surface using the well metallic construction as the transmission medium. It can be either wireline or coil tubing deployed into existing wells as a retrofit device or alternatively deployed in a mandrel configuration as part of the completion. The gauge can be installed in well tubing conduit or production casing or liner using the XN nipple profile and gauge hanger with no flow restriction. Cableless pressure gauges are installed in the wellbore without the need for a rig to achieve continuous real time pressure and temperature data transmission from down-hole to surface without a direct cable connection in the well. The big safety advantage of this gauge is that it can be set and left in hole using wire-line tools for about three years, which improves platform safety that eventually optimize the resources utilization. System components requirements are gauge, receiver, signal pickup on well, ground anode, power for the receiver (solar, portable battery or main connection) and SCADA data interface.

Deployment Procedure

Prior to addressing the scope of work and strategy behind the trial test, below are the major deployment steps. Fundamentally, the cableless gauge is rigged-up with slickline, then a hollow gauge hanger is set inside the well and the line is rigged down.

1. Install pole for receiver and solar panels.
2. Dig trench for cables and anode.
3. Attach signal pickup on well.

> Cableless pressure gauges are installed in the wellbore without the need for a rig to achieve continuous real time pressure and temperature data transmission from down-hole to surface without a direct cable connection in the well.

4. Install ground anode.
5. Run cables from well and anode to receiver.
6. Mount receiver and terminate cables.
7. Rig up slickline equipment, PCE and drift well.
8. Program and test gauge at surface.
9. Assemble gauge vertically into lubricator.
10. RIH with gauge and test gauge by analysing data on the receiver.
11. Set hanger in nipple profile and gauge inside the well.
12. Rig down slick line equipment.
13. Configure the receiver at the surface.
14. Connect receiver to SCADA system to transmit data.

The trial period was oriented to two scopes, 1) initial trial lasting for about 100 days and was completed in two stages and 2) reliability testing. Stage one of initial trial lasted for around 10 days. The objective of this stage was to prove the wireless gauge communication, quality and frequency of the pressure and temperature data. In addition, to determine the optimal tool settings required for robust wireless communications from downhole to surface. Stage two lasted for roughly 90 days. The objective was to program the wireless gauge with the optimal settings as defined in stage one. This was achieved through incorporating a transmission schedule to simulate a two-year or longer data acquisition program. This is mainly to prove that communication can still be acquired after one year period. The second tier of planned series of channel tests enabled the determination off performance with shorter battery configurations, tool communication in the liner Vs tubing (figure 3 shows the tool communicating inside 4-1/2" tubing).

Trial Test Objectives

The cableless gauge was installed on an onshore Well-A by Saudi Aramco wireline inside the production tubing, and the gauge effectively transmitted temperature and pressure electromagnetically through the tubing steel to surface then to the control room of a Gas Oil Separation Plant (GOSP). The success of this installation encouraged further evaluation of the technology in the same well extending the testing period by 90 days to verify the battery run life, gauge reliability and centralizer contactability. The latter is necessary for better signal and gauge energy saving. Additionally, the exceptional first trial results supported conducting another trial test at an offshore well. Well-B

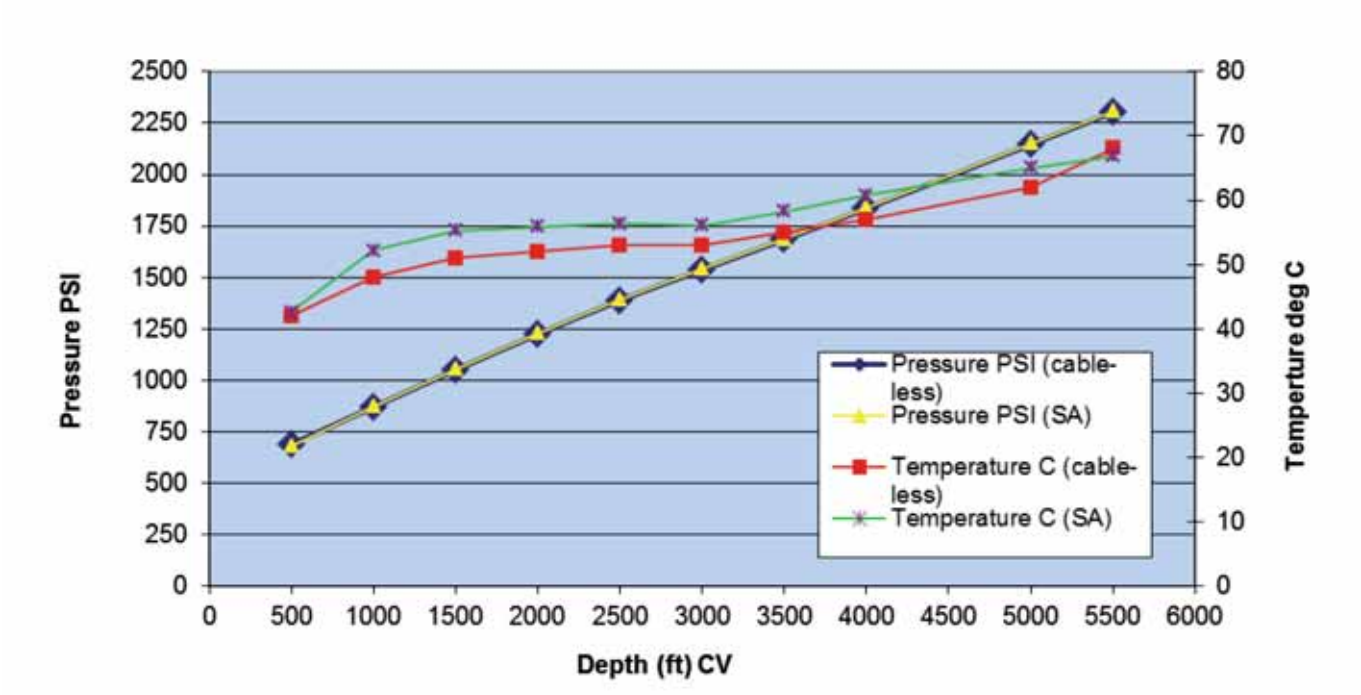

Figure 5: Pressure and temperature readings of Saudi Aramco wireline gauge compared to the cableless gauge.

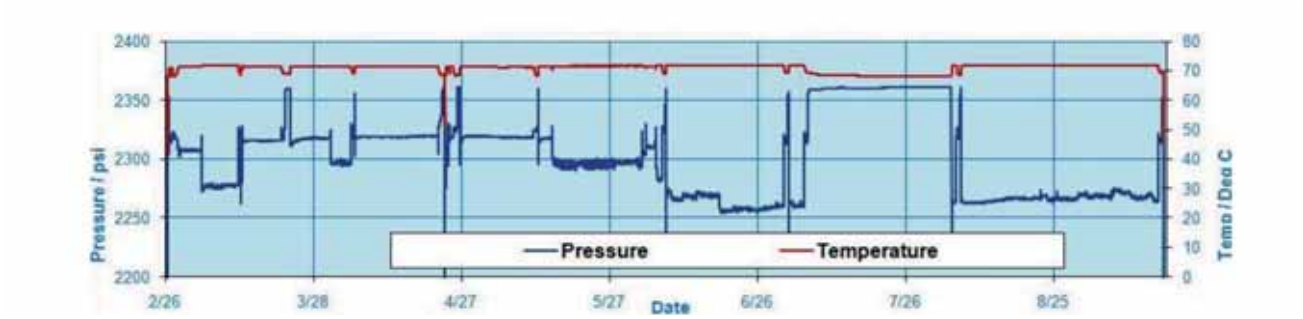

Figure 6: Pressure and temperature readings for certain period of the extended trial.

was selected to test this technology in an offshore environment and with a different well configuration. The last well, Well-C was an oil observation well.

The trial test objectives of this first time-deployed technology were to test:

1. The signal strength received at surface.
2. The running, setting and retrieving tool.
3. The gauge accuracy compared to the conventional methodology.
4. The surface devices compatibility and data transmission through existing SCADA system.
5. The matching accuracy of the gauge memory data and the surface captured data.
6. Best future equipment modifications and way forward.

An Extrapolation to Datum Empirical Study

This section of the paper provides a solution for obtaining the datum pressure from solely one sensor installed in wells, such as the case with cableless, wells equipped with either only on PDHMS or two PDHMS but one is malfunctioning and ESP wells during shut-in period. To prove the applicability of the proposed technique which uses mixed fluid gradients for datum pressure estimation, over 100 wells were studied to estimate the right pressure gradient that can be utilized

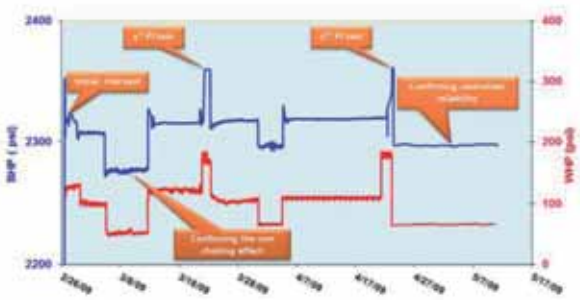

Figure 7: Results analysis and tests conducted.

to extrapolate the downhole pressure measurement to datum pressure[3]. The datum pressure extrapolated using this method was compared to the datum pressure extrapolated using fluid gradient acquired through the conventional two stops of the regular slickline conveyed gauges. The study also used linear programming to find best-fit gradients. Sensitivity analysis were conducted against different gradients and found insignificant differences.

No change in procedure was considered for acquiring SBHP values from ESP sensors where those were installed in the field. This is mainly because these pumps have two pressure sensors, one at the multi sensor assembly (considered to be the intake pressure) and one at the discharge. Intake and discharge pressure sensors are connected to SCADA and can be read at the engineer's desktop using PI data historian system. The collected pressure data at static condition revealed that these pressures cannot be depended on to form a representative gradient. Most calculated gradients were less than expected and some came extremely erroneous. Preliminary analysis indicates that this is largely due to suspected imprecise reading at the discharge pressure as it is masked by different components of the ESP, whereas pressure from the multisensor assembly can be more reliable due to its location being the lower section of the pump and hence would have accurate gauging of the formation pressure. This triggered the need to start a comparison study, to look back at all SBHP surveys conducted using the conventional electronic gauges with a gradient calculated from two pressure stops and then back calculate the datum pressure using the water cut of each well at the time of the SBHP survey and compare the two readings. The exercise was done for over 300 wells. The practice was then narrowed down to the selection of 100 wells based on:

- Reservoir completion.
- Availability of valid water cut value at the time of the survey.
- Matching reproduced datum pressure to the originally calculated datum.

Linear programming of Excel was used here to iterate for best solution by utilizing the Solver Add-in. In the solver equation the objective was set to minimize the sum of the absolute values of the entire difference between datum pressures in both cases, the iteration values were oil and water gradients and they were restricted by minimum values of 0.361 psi/ft and 0.461 psi/ft respectively. The optimum values came up to be equal to the minimum set values. Results were overwhelmingly encouraging. Figure 4 includes the final datum (measured/calculated) pressure using wireline method and assumed gradient. The majority of data difference falls within the +/- 5 psi. The results open doors for variety of applications such as estimating pressure from ESP wells during shut-in, pressure from PDHMS if one gauge malfunctions, and in the future for pressure from cableless gauges if one gauge is installed in a given well.

Factors Affecting Cableless Technology Performance

There are several factors that can affect the performance of this technology; these all combine to ultimately define the performance envelope of the system. The factors include:

1. Well resistivity; the gauge utilizes the available steel of the well structure as a transmission medium for the EM signal, therefore any formation that is in contact with the well structure that also has the ability to conduct electrical energy can have an effect on the

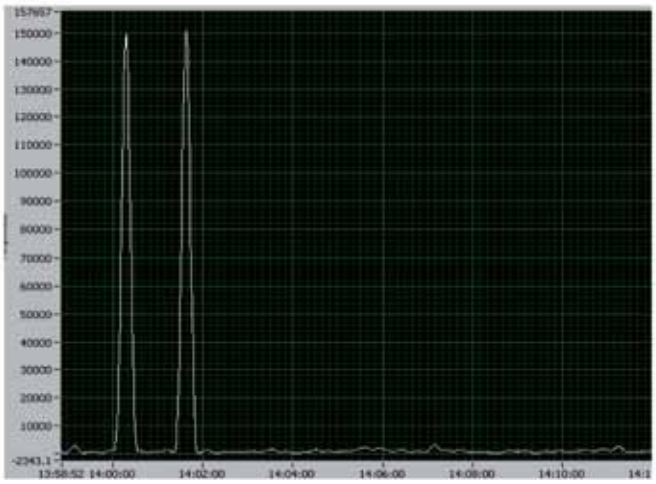

Figure 8: Strong signal as received during the trial.

system performance that needs to be accounted for.

2. Setting depth; the greater the transmission distance the more energy is required to transmit the EM signal – especially when the formation resistivity of the well is also taken into account. The system uses an "energy per bit" concept, therefore the more energy needed to transmit, the less readings that can be provided.

3. Tail ratio; it is the ratio of measured distance from the system to the cased depth of the well and the measured distance from the system to surface. Generally a Tail Ratio of 1:10 is desirable.

4. Downhole power availability; since there is no wire to power the downhole components from surface, there becomes a requirement for the wireless product to store energy downhole. Because only a finite energy source is currently available (in the form of Lithium batteries) this energy source has to be managed in such a way as to give the optimal number of data transmissions over a given time period at a given depth.

5. Condition of tubulars; for the system to function optimally it is necessary to have a good electrical continuity between the system centralizers and the tubing/casing. Therefore, if the well bore is badly corroded, or is covered in scale, the poor continuity between the system and the tubing/casing could affect its performance. Likewise if the tubing or casing is parted this will cause poor electrical continuity therefore affecting the system performance.

6. Surface earthing (i.e., grounding); the downhole data is transmitted to surface utilizing EM energy. Consequently, to successfully decode the data it is necessary to have an earth reference available where the decoding is taking place.

Results and Analysis

The two objectives of receiving strong signals at surface and proving simplicity of running and retrieving the gauge were achieved during the first attempt on the onshore Well A as the cableless assembly was run and recovered by wireline easily. The test indicated strong waves propagation that were successfully transmitted from bottomhole and recorded at surface with no interruption for four days. For data accuracy verification, Well A trial test included running a high-resolution electronic wireline gauge on a different day as a base reference to compare both gauge survey results and evaluate the new cableless technology figures accuracy. The comparison showed that the high-resolution electronic wireline gauge and the cableless gauge have excellent pressure data match. Additionally, a further compatibility test was performed with the surface equipment and found to be fully well-suited with Saudi Aramco SCADA system as Well A data was successfully configured and displayed at the offshore GOSP.

All shortfalls were captured and lessons learned were applied in a second modified trial test procedure, designed and carried out on Well B, in an offshore environment and different well profile. Unlike Well A, the high resolution electronic wireline gauge and the cableless gauge were run in tandem at Well B to eliminate depth slippage effects and provide similar

> The preliminary results indicate that the gauge can communicate pressure and temperature readings to surface for more than two years.

evaluation conditions. The pressure data analysis for Well B trial test was found to be exactly matching at all depths of investigation for both gauges (figure 5). It was evident that the reading variance was further reduced to one decimal when the two gauges were run together in tandem. The trial also showed that the gauge is not affected by depth nor flow regimes. Therefore a decision was made to continue hanging a gauge in Well A for 90 days to further assess the gauge durability, battery life time and hanging tool compatibility. Figure 6 shows the results during this period. The gauge was programmed to send data to surface every three hours. This is aimed to prove that the gauge can remain in the hole and keep transmitting pressure data accurately as long as possible. The last test was rate testing Well A with the tool hung in hole which confirmed the ability to produce as much as 8+ MBFD through the hollow hanger with no restriction. Generally, data analysis confirmed the cableless gauge readings to match those of the high-resolution wireline electronic ones. It is a perfect match for pressure and an engineering acceptable match for temperature (figure 5). The cableless memory gauge data was also compared with the data received at surface and found to be equal re-assuring gauge competitiveness of sending strong signals that is independent of gauge depth and flow regime and possibly time as it is being tested[2].

In brief, the evaluation of the cableless technology was carefully designed to include current and future implications. The initial trial test of seven days was successfully completed and all objectives were met. Also the concern of the ability to produce the well with no restriction was confirmed as the well was producing at full potential. The ability to conduct a productivity index (PI) at any desired time to evaluate well performance was also tested. It took about six hours to reach the stabilized PI. The well was shut-in (SI) for almost twenty hours and the PI was recoded. Another PI test was conducted to assess the first PI and confirms its accuracy (figure 7 shows the details of those tests). The centralizer was proven to be reliable of transmitting high signal strength of quality data to surface. Figure 3 shows the signal strength of sending data. The signature of the bottom-hole pressure data in blue showed matching trend with surface wellhead pressure in red color recorded via SCADA as can be foreseen in figure 7. The results attained from the cableless gauge exactly matches those attained from the conventional method of attaining SBHP.

The results showed that the gauge had good pressure and temperature reading to surface when compared to historical surveys on the subject well. The cableless gauge had good communication at all depth points in the well. The preliminary results indicate that the gauge can communicate pressure and temperature readings to surface for more than two years.

Understanding the well's data frequency requirements is essential to enable proper planning the gauge duration. For instance, for wells that require data after every two weeks, the gauge can be programmed to communicate pressure and temperature up to five years. The gauge

> The technology can be retrofitted into an existing well to enable real time downhole data acquisition with no cabled connection required to the downhole gauge.

reliability and accuracy were tested for nine-months. This extended trial test showed continuous data transmission through steel pipe every three hours with good pressure response at different production rates. Overall, the trial test showed reliable data that are in excellent matching accuracy with the electronic gauge both onshore and offshore.

Trial Test Assessment

The technology of cableless pressure and temperature downhole gauge system was trial tested successfully as an alternate downhole monitoring tool that provides continuous real-time pressure and temperature data. The trial aimed at testing the credibility of the technology and its ability in reducing the routine well interventions for SBHP/T especially in offshore environment. The trial was successful and was extended to test the unit reliability as well. This trial test was intended to potentially improve well intervention safety and control cost in a harsh offshore environment. The technology further helped optimize resources and meet the annually increasing well services requirements. Currently, it has been extensively tested in three different wells for longer periods, onshore and offshore, including single and multi-well platforms. The analyses of the first cableless trial test indicated excellent matching results as opposed to wire-line electronic pressure gauge. Saudi Aramco was the first in the Middle East to adapt such technology[2].

In summary, the three subject-test wells have also shown data that are in excellent matching accuracy to the currently utilized electronic gauges both onshore and offshore. In addition, the 9-month extended trial test showed continuous data transmission through the steel pipe every three hours with good pressure response at different production rates. Strong signals for pressure and temperature were received at the surface at all times, as shown in figure 8. The running/setting and retrieving of the tool were proven to be operationally simple and safe. The cableless gauge pressure and temperature data accuracy was found to match the conventional high-resolution electronic gauge that is currently used for routine pressure and temperature surveys. Both the memory data vs. the surface captured data were compared and found to be perfectly matching. The surface equipment was function tested and found to be fully compatible with Saudi Aramco SCADA system as data was successfully transmitted.

> Cableless can be deployed with a rig or without; offering huge cost savings and assurance of data attainment in real-time in the case of PDHMS failure.

Lessons Learned

The main features and benefits of the technology in well monitoring application as well as the lessons learned can be summarized as follows:

• The technology can be retrofitted into an existing well to enable real time downhole data acquisition with no cabled connection required to the downhole gauge.
• The ability to retrofit install a real time data acquisition system means that current field operations involving the regular deployment of memory gauges from barges can be avoided.
• The flow restriction as a result of hanging the gauge can be easily minimized or eliminated by better modification of the hollow hanger to accommodate as high as 10 MBFD with no significant pressure drop.
• It was learnt that a special wireline scratcher or a brush is to be used for old tubing installation to improve tool to tubing contact. Chemical cleaning can be an option.
• The best time for data collection was found to be at midnight until morning due to low boat traffic. Therefore, data receiving can be programmed during the first six hours of the day.
• Confirming the low level of noise with no anode installation is another step toward cost containment, simplification of installation and installation space optimization. Grounding to a nearby well has proven to be as effective toward installation cost reduction.
• Running and retrieving the gauge tools was proven to be operationally simple and safe. A modified centralizer is now recommended for better conductivity and operational flexibility.
• EM signal means no requirement for feed-throughs or penetrations at the Plug or Tubing Hanger or Xmas Tree.
• The EM telemetry is addressable, therefore enabling multiple installations into a single well for zonal reservoir monitoring purposes.

Conclusion

The downhole cableless pressure and temperature system has been successfully tested as an effective monitoring device with excellent results. The trial test was carried out on Wells A, B & C – selected to confirm technology operability in an extremely complex environment. The key objective of verifying the delivery of strong signals to surface was certainly achieved despite gauge depth and flow regime. This system was also proven to be compatible with Saudi Aramco SCADA system and showed superior data

matching when compared to wireline high resolution gauge. Affirmatively, this is a potential technology that can simplify logistics compared to the conventional pressure/temperature surveys and PDHMS system with a great compelling application for single well platforms, free standing conductors and tripod platforms that mostly reduces offshore barge efficiency.

Summary

- The technology presumes being best in wells associated with an offshore and/or harsh environment articulating dramatic reduction in data-acquisition visits to such locations hence provides an extra room for better resource utilization optimization.

- Old wells that would have been installed with PDHMS if were available seems to be the most favorable options for such application.

- The technology complements the PDHMS where a rig is required for installation. Cableless can be deployed with a rig or without; offering huge cost savings and assurance of data attainment in real-time in the case of PDHMS failure. In other words, it proved to be a cost containment competitor to the routine slickline intervention and a supplement to the PDHMS.

- The deployment is associated with fewer barge visits, minimizing human exposure and increasing efficiency especially in surveying offshore key wells that are normally surveyed 4 times/year. It has a huge potential that simplifies logistics compared to the conventional pressure and temperature surveys and PDHMS with a possible relevance for single well platforms, free standing conductors and tripod platforms to minimize visits requirements.

- The deployment of this technology has proven to enhance data acquisition, add economic benefits, help increasing well service vessels efficiency, improve operation safety and simplify logistics.

- The continuously attainable datum pressure data are essential to monitor any abnormal well behavior.

- Saudi Aramco will continue to the widely utilize such technologies with due diligence of capturing the lessons learned that will facilitate the way forward for this kind of application to be used in other Saudi Arabian fields, especially those in a) offshore, b) in harsh environments, c) in close proximity to populated residential areas and 4) with minimal intelligent field infrastructure.

- The big safety advantage of this gauge is that it can be set and left in hole using wireline tools for three years. This reduces the frequent barge visits from 12 times to only one time in every three years, which results in a significant safety improvement on single well platform and well service resources optimization.

- Categorizing wells based upon the frequency of data acquisition requirements is important to manage the gauge duration.

- Broad utilization of this technology as appropriate helps in mitigating intervention risks, improving offshore traffic safety through minimizing visits, optimizing resources utilization and reducing operating expenditure.

Acknowledgement

Authors' appreciation goes to Saudi Aramco management for granting permission to publish the paper. A special thanks goes to Hassan B. Al-Qahtani, Nami A. Al-Amri, Eddy Sarhan A. Azizi of Saudi Aramco and to Brian Champion of Expro Group for their contribution and insightful feedback.

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Water Control and Relative Permeability Modifiers – Laboratory Screening for Improved Results in a Middle East Context

By Clive Cornwall, Corex (UK) Ltd.

Introduction

Relative Permeability Modifiers (RPMs), after a period of extreme user scepticism, are once again being considered as an effective method of controlling unwanted water production in both oil and gas reservoirs. The inclusion of RPMs in the conformance engineer's portfolio of possible remedial solutions is being driven, in part, by the introduction of new and improved products by a number of major chemical suppliers. These companies are responding to the ever growing number of maturing fields, in all hydrocarbon provinces including the Middle East, which are plagued by excessive water production and to the demands of clients to extend viable hydrocarbon output beyond current predictions.

The RPM's original fall from grace was driven by extravagant claims for universal applicability, in essentially all lithologies. The point has been made that if the majority of RPM treatments had met with measurable and general success, their deployment would not have declined quite so dramatically. It may be argued that this pattern of initial misplaced optimism, followed by a broad rejection of the products and the techniques, could ensnare the present range of products, thereby dissipating their believed potential.

There is a significant body of research concerned with the theoretical mechanisms that enable RPMs to suppress water flow while permitting hydrocarbons to move without undue interference. A common thread running through this work is a realisation that the success or failure of an RPM treatment is dependent on the unique combination of factors found in the target well and reservoir. Of the myriad of contributing elements to be considered, wettability is of particular importance, as it directly determines the level of polymer attachment and subsequent retention.

A realisation of the importance of wettability to the success of an RPM treatment would surely lead to a requirement for the determination of the wetting preference of the formation to be a key component of the pre-injection planning. Unfortunately in the majority of cases this measurement step is missing from the sequence. In fact in correspondence with one of the major suppliers the point was made that a formation is presumed to be water-wet unless advised otherwise by the client. Where the wetting preference is predicted not to be water-wet, the standard advice is to "clean" the formation, to achieve the desired water-wet preference. Such assumptions are not routinely checked to ensure the formation can be prepared to maximise polymer adsorption and to minimize displacement during subsequent production.

This paper seeks to make the case for an integrated core analysis and petrographic screening study, in

conjunction with one or more RPM formulations, to determine which product is most suited to the prevailing conditions. It also affords an opportunity to modify a particular RPM formulation to maximise its potential and where a clean-up chemical is to be used, to ensure it will have the desired effect.

Background

The wide gamut of test formats available to the core analyst is many and varied, and provides a powerful device in defining the original condition of the rock material and the saturating fluids. The inclusion of petrographic examination, in the form of thin section analysis, SEM and XRD enhances this original assessment process. Thereafter, the ability to perform testing following on from treatment with both conditioning and RPM chemicals generates comparative data sets for the determination of "before and after" trend patterns, thus suggesting the effectiveness of each selected product.

The Relative Permeability Modifiers that would benefit from an integrated package of core analysis screening are the non-sealing, water soluble polymers, whose purpose is to reduce the flow of water into the wellbore, without unduly suppressing the production of the oil phase. The manifestation of the alteration in the flow patterns is found in the effective water and oil permeabilities, and in the fluid saturation profiles. Such parameters can be measured under reservoir conditions of pressure and temperature, with crude oil and simulated formation brine, as part of the core analysis screening.

The effective oil and water permeabilities, on a before and after treatment basis, are translated into (Residual) Resistance Factors to water and oil, which are taken as a measure of the success of the RPM in controlling water production while maintaining the passage of oil.

The (Residual) Resistance Factor values available in the literature supplied by the chemical companies are encouraging, although the use of standard sandstones, which are naturally water wet, reduces their applicability to specific well conditions. The impact of wettability is discussed later in the paper and its importance is demonstrated in terms of the relevance to polymer attachment and the movement of fluids within the pore system.

Candidate Test Formats

A typical screening exercise would draw upon the following test formats to define the important petrophysical and petrographic characteristics that have a potential bearing on the success of the RPM treatment.

- Combined Amott/USBM Wettability, together with sourcing of suitable core material and its possible restoration.
- Effective Water Permeability at Residual Oil Saturation and Effective Oil Permeability at Irreducible Water Saturation for (Residual) Resistance Factor to Water and Oil
- Specific Gas Permeability, Pore Volume and Porosity, with Dean Stark Extraction
- Mercury Injection Capillary Pressure for pore throat size distribution
- Petrographic Analysis - Thin Section, SEM and XRD

Each of these formats is discussed in the subsequent subsections, culminating in a generic preparation and measurement sequence, presented in Figure 1.

Wettability – Comments and Determination

It is generally accepted that the water soluble RPM products being offered by the major chemical suppliers require the rock matrix to be preferentially water wet, to ensure robust adsorption and attachment, and prolonged adhesion. If all reservoirs had an affinity to water in the presence of oil, the need for screening would be removed. The assumption that all reservoirs are very strongly water-wet has formed the basis of a significant body of reservoir engineering practice for some considerable time. The rationale for this assumption being that water originally occupied the reservoir trap and that as oil swept the formation the water phase would be retained by capillary forces in the finer pore spaces and as films on grain surfaces overlain by oil. However, there is a growing movement away from this viewpoint, based on published evidence into the effects of crude oil on wetting behaviour, towards an acceptance that most reservoirs are at wettability conditions other than very strongly water wet. Extensive testing has shown that reservoir wettability can cover a broad spectrum of wetting conditions from very strongly water wet to very strongly oil wet. Within this range complex mixed wettability conditions given by combinations of preferentially water wet and oil wet surfaces have been identified. Mixed wettability in the reservoir often results from surface-active molecules in the crude oil adsorbing onto grains over time.

The point has been made that rock properties such as relative permeability and capillary pressure, depend on the distribution of water and oil in the pore space. In

Mineral	Percent
Quartz	83
Feldspar	5
Clays	9
Other Minerals	3

Table 1 – Typical Mineralogical Content of Berea Sandstone

order for laboratory measurements to be representative, it is necessary for the pore level distribution of the fluids and the wettability to be the same in the laboratory as in the reservoir. Unfortunately much, if not all, of the laboratory based proving of the RPM chemicals has been conducted on standard sandstone plugs, such as Berea (see table 1). These sandstone plugs are cleaned with solvents prior to saturation with brine and oil, which creates a uniform wetting preference. Anderson in his review of the technical literature with respect to rock-oil-brine interactions and wettability observes that when all surface contaminants are carefully removed, most minerals, including quartz, carbonates and sulphates are strongly water-wet.

The requirement for a water-wet surface casts doubt on the use of RPMs in carbonate reservoirs. Published studies have concluded that carbonate reservoirs are typically more oil-wet than sandstone. Such differences are linked to different adsorption characteristics of silica and carbonate surfaces, in terms of simple polar and crude oil compounds. In recent field investigations performed on carbonate cores from the Middle East, the trend was for a general intermediate to slightly oil wet preference in the oil column. However, the ability to screen carbonate core provides an opportunity to test whether the presumption is valid or whether a modification of the formulation would be beneficial for RPM adsorption.

The preferred method for measuring the wettability of the core samples, whether fresh, cleaned or restored state is the Combined Amott/USBM method. The combination of the two techniques ensures all possible wetting preferences can be determined, including mixed and non uniform wettability.

The generation of the wettability indices would be undertaken on a specific suite of plugs. For the determination of the inherent wetting preference of the reservoir, the plugs would be in either a fresh or restored condition (see below). When it is necessary to assess the impact of the cleaning chemical, the plugs would be flushed with the selected chemical prior to the wettability testing.

The Condition of the Test Core

The screening process is dependent on the securing of representative core material, in terms of its petrophysical and petrographical properties.

The preferred option is for the cutting and trimming of plugs at wellsite at selected depths across the reservoir section. Ideally the core should be taken with a low invasion coring system, to minimise mud filtrate invasion. It has been shown that oil based mud filtrate will alter the wettability of the reservoir rock. Emulsifiers and surfactants included in these fluids, even at low concentrations, have been shown to be responsible for a change in wettability. Water base mud will artificially enhance the residual water saturation present in the pore space and may contain wettability altering surfactants. The plugs, taken from the "undisturbed" centre of the core would be preserved in a closed environment pending analysis.

If it is necessary to use archived core, which is either inappropriately preserved or has suffered long term atmospheric exposure, it is advisable to restore the core to re-establish the representative wettability and saturation profile. In the laboratory the reservoir wettability of cores can usually be restored by duplicating the process that established the wettability in the reservoir (31).

Formulation A

Permeability Flow Rate	(R)RF Water	(R)RF Oil
1 ml/min	25.3	2.1

Based on a restored state sandstone plug with a specific gas permeability of 125 mD. Plug flushed with treatment fluid prior to injection of RPM and shut-in for 12 hours.

Formulation B

Permeability Flow Rate	(R)RF Water	(R)RF Oil
1 ml/min	39.2	1.8

Based on a restored state sandstone plug with a specific gas permeability of 210 mD. Plug flushed with treatment fluid prior to injection of RPM and shut-in for 12 hours.

Table 2 Example – (Residual) Resistance Factors for Water and Oil Generated from Two RPM Formulations

• Establish a water-wet state by solvent cleaning. A clean mineral surface is indicated by a water-wet condition since clean silica and calcite are strongly water wet. This is a typical sequence but there will be exceptions, for example when fatty acid emulsifiers are added to an oil base mud (32). In such cases the cleaning sequence must be adapted to the specific case.

• Establish saturations representative of the reservoir, or more precisely, a representative pore-level distribution of water and oil.
• Ageing in the presence of a high saturation of crude oil at reservoir temperature.

The use of core plugs that have been vigorously cleaned with solvents, such as xylene and methanol, without subsequent ageing in crude oil, is not advisable as it will skew the following Permeability Resistance Factors toward an overly optimistic position. It will also prevent an unbiased assessment of any clean-up chemicals that may be recommended by the RPM suppliers.

Determination of the (Residual) Resistance Factors for Water and Oil from Effective Permeabilities to Water and Oil

The plugs, whether in a fresh or restored condition, will be at irreducible water saturation with the remaining pore space filled with oil. They are mounted in individual hydrostatic core holders, a representative effective reservoir overburden pressure is applied and the assembly placed in an oven set at the reservoir temperature (see Figure 2). Following a period of stabilisation the following conditioning and measurement sequence is undertaken:

• Effective oil permeability at irreducible water saturation (Formation to Wellbore)
• Flood to residual oil saturation (Formation to Wellbore)
• Effective water permeability at residual oil saturation (Formation to Wellbore)
• Flushing with cleaning chemical (if required by chemical supplier and operator) (Wellbore to Formation)

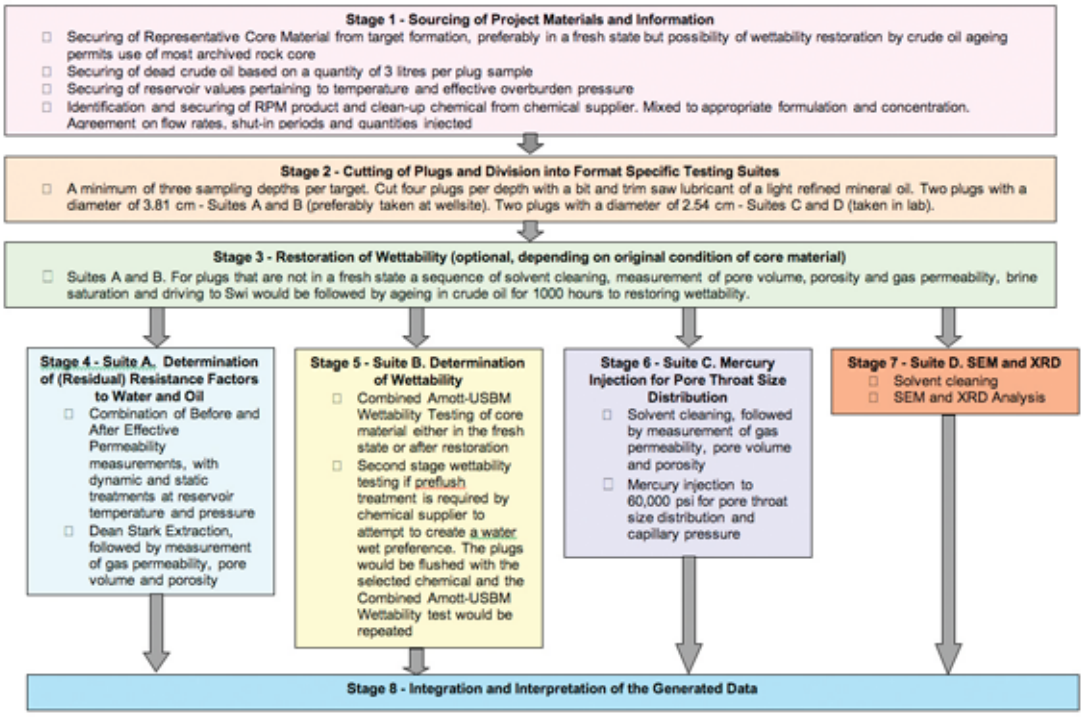


Figure 1 - Flow Diagram for Programme of RPM Screening

- RPM treatment (Wellbore to Formation)
- Flood to residual water saturation (Formation to Wellbore)
- Effective Oil Permeability (Formation to Wellbore)
- Flood to residual oil saturation (Formation to Wellbore)
- Effective water permeability at residual oil saturation (Formation to Wellbore)

This generic sequence can be modified to reflect the specific requirement of the chemical supplier, in conjunction with the operator, in terms of flow rates, shut-in periods and quantities injected. The selection of the flow rates is of particular importance to minimize polymer stripping during subsequent formation to wellbore production. The flushing cycles can also be altered should there be a need for over-flushing or focusing on a single phase rather than both water and oil.

Additional analysis may also be included to monitor the amount of RPM polymer present in the effluent to chart the rate of displacement associated with prolonged flushing after treatment.

The pairs of effective water and oil permeability values provide a measure of the efficiency of the RPM treatment in terms of (Residual) Resistance Factors (see Table 2):

(Residual) Resistance Factor (to water and oil) = Permeability (mD) Before Treatment / Permeability (mD) After Treatment

The end point saturation values of irreducible water and residual oil may also be taken as indicators of the impact of the cleaning chemical and RPM in terms of water retention and the production of the oil phase.

Specific Gas Permeability, Pore Volume and Porosity, with Dean Stark Extraction

On completion of the fresh or restored state testing, the end point water and oil saturations are fixed by Dean Stark extraction. The base parameters of gas permeability, pore volume and porosity of the clean and dry plugs are measured under ambient conditions. The end point fluid saturations are expressed as percentages of the measured pore volume.

Principal Components:

Large capacity oven
Fluid delivery system comprising Constant Flow Rate pumps, 0.0001 to 45ml per min, 10,000 psi mwp and a pair of floating pistons housed within the oven
Integrated data acquisition and pressure (absolute and differential) detection system
Hydrostatic core holder, 10,000 psi mwp
Overburden pressure system, 10,000 psi mwp

Fig 2. Reservoir Conditions Test Rig for rpm Screening.

Mercury Injection Capillary Pressure and Petrographic Analysis

To understand the interplay between the RPM and rock matrix, an in-depth characterisation of a representative range of samples from the available core material is recommended.

Mercury Injection to 60,000 psi will fully quantify the pore throat size distribution, which is a key factor in the control of flow in general, and the subsequent suppression of water movement within the pore system.

Thin Section, SEM and XRD analysis assists in the interpretation of the data generated by the screening process. For example, core material containing coal can be naturally neutrally wet, as suggested by an inability to achieve a strongly water wet preference during prolonged solvent cleaning. Another example may be found in the oil wetness of the North Burbank unit, which is caused by a coating of chamosite clay on the grain surfaces. Clays in general can adsorb asphaltenes and resins that can make the clays distinctly oil wet. Once attachment has occurred, as found with kaolinite and montmorillonite, it is difficult to remove. The presence of carbonate cements may also be detected through petrographic examination and will add an appreciation of the contributing elements in a sample's wetting preference.

Conclusions

To maximise the benefits of RPM treatments, whether directly into the matrix or associated with fracturing, an understanding of the properties of the target formation is vital. This knowledge base will also assist in selecting the pre-treatment processes and solutions that are applied to create a water wet preference for polymer attachment.

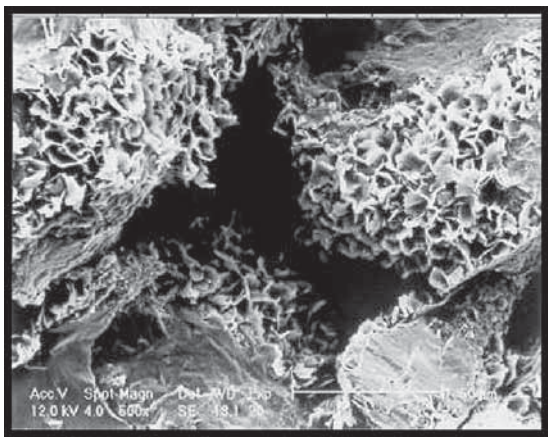
Screening of the representative reservoir rock plugs under simulated reservoir conditions diminishes uncertainty. It also removes the current reliance on standard sandstones or cleaned reservoir core, with its encouragingly water wet preference, to predict the successful suppression of unwanted excessive water production.

Formation Damage Laboratory Testing – Cost Effective Risk Reduction to Maximise Recovery

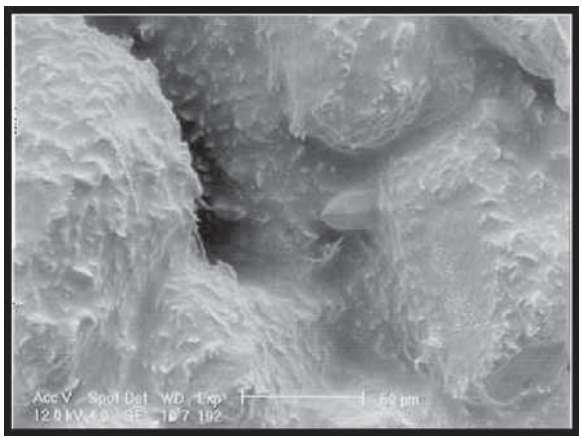
By Clive Cornwall and Bassem Yousef, Corex.

In recent years the oil and gas industry has seen rising costs associated with various operational activities such as drilling, completing and treating wells. However, economic pressure is not the only challenge within the market, environmental responsibility and the trend towards deeper drilling has led to many operators taking a total quality management approach to enable successful well operations. Any additional information that can be obtained to assist with operational decisions is much welcomed. Laboratory testing is viewed as a cost effective and low risk route to gather vital information in understanding the areas which may create risk during the life of a well. Appropriately structured testing programs including advanced interpretation techniques can have short, medium and long term benefits. This article will set out the main arguments to undertake laboratory assessments, and discuss some of the areas where the results can be particularly valuable.

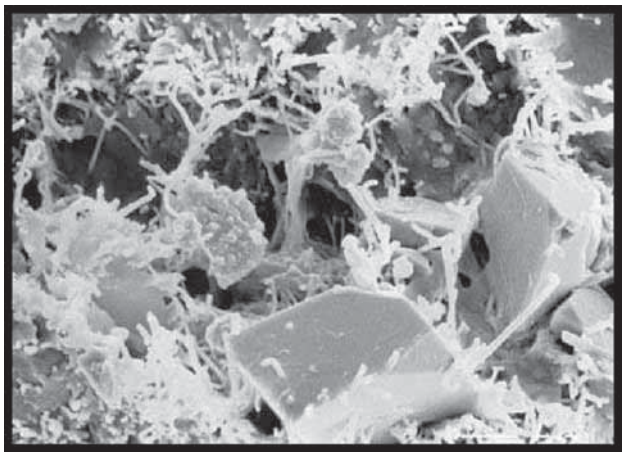
Mechanisms which have an unfavourable economic impact can occur at any point during the life cycle of the filed such as drilling, completion, production, injection, treatment, and stimulation. These mechanisms which are termed as "Formation Damage" can manifest themselves in various ways, but fundamentally involve interactions between the reservoir (rock and fluids) and the introduced operational fluids and hardware.



Before Test Dry SEM image



After Test Cryogenic SEM image



Damaged illite from unsuitable cleaning technique

Drilling mud infiltration, poor mud-cake clean-up, fluid retention, fines mobilisation and pore blockage, fluid incompatibility and precipitation, emulsions/ sludges, removal of cement, clay swelling, and sanding are all examples of mechanisms which can have an impact on productivity or injectivity.

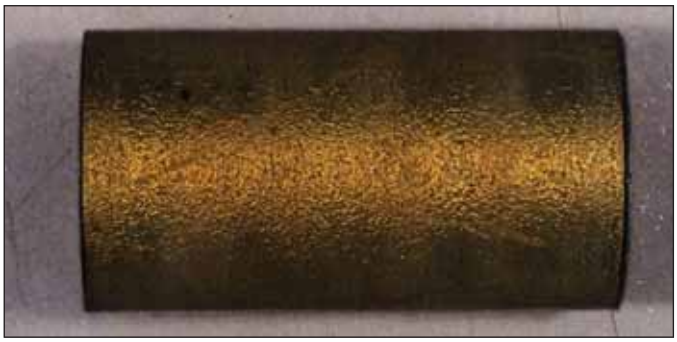
Laboratory testing can be performed to identify these damaging mechanisms, and with the correct interpretation useful recommendations can be made on ways of avoiding or removing them. The testing therefore becomes part of the quality management "Plan, Do, Study, Act" cycle: laboratory testing checks for problems or mechanisms, defines the options available for avoidance, tests the solutions for effectiveness, and provides feedback to aid in implementation. In terms of risk, the greater level of understanding can not only reduce risk, but add value to the planning process, as it is significantly cheaper to experiment in the laboratory than the field. A key aspect of laboratory testing is that it is direct measurement, whereas models are indirect or derived measurements; test data can therefore be used as inputs which consequently supplement or improve models. In addition, independent testing is key in the "calibration" of vendor recommendations on fluids and hardware, allowing comparison across vendors, fields, and operators.

Testing to examine wellbore operations typically consists of preparing core samples to representative wellbore conditions, and simulating the operational sequences under consideration. Care must be taken throughout the process, to avoid any impact of the equipment or procedures on the outcome of testing.

> Drilling mud infiltration, poor mud-cake clean-up, fluid retention, fines mobilisation and pore blockage, fluid incompatibility and precipitation, emulsions/ sludges, removal of cement, clay swelling, and sanding are all examples of mechanisms which can have an impact on productivity or injectivity.

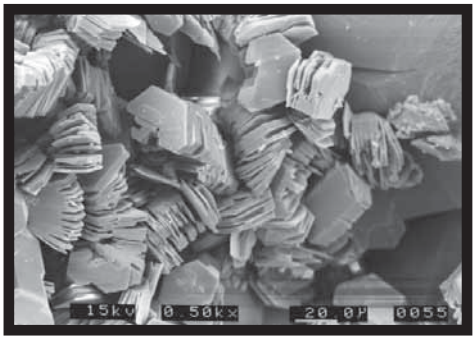
Equipment must not corrode, even when flowing strong acid under HPHT conditions; the techniques used to prepare the samples (cutting, cleaning, drying, saturation, permeability measurement) must not create artefacts; and the conditions and sequence tested must be representative in terms of the fluids and hardware being considered, exposure times, temperatures, pressures, overbalances and underbalances. Expert consultants assist with the test design (e.g. mud cake development, horizontal versus vertical core holder orientation, wellbore operational sequence to be evaluated) so that the required objectives are met and also to ensure that test results are not misleading. The output data from testing typically includes permeability measurements, filtrate loss volumes, production/ injection plots, and sample photographs, which are all used in aiding conclusions.

After having performed a well-designed and executed test it is, however, just as (if not more) important to understand the results fully. Relying upon permeability alone creates a high risk, as in short core samples it is common for both pore restricting (e.g. drilling mud infiltration, scale precipitation, fluid retention) and pore-enlarging (e.g. clay fines removal, cement removal, saturation change) mechanisms to be seen. The combination of these can lead to increases, decreases, or no overall change in permeability, even though there are a number of mechanisms which could potentially cause problems in the field. For example, in short core samples it is relatively easy to mobilise and remove high surface area clays, which will increase permeability, where in the field increased transit distance and concentration as the particles move towards a smaller volume in the near-wellbore area can lead to significant reduction in



24-carat gold film prevents gas leaking from the core under hydrothermal conditions.

Corexís advanced HPHT Scale Rig performs many tests to establish Scale Risk Assessment (SRA).



Abundance of pore filling and grain coating Kaolinite clay booklets.

pore space. To reduce risk and increase understanding of results, interpretative geological analysis including scanning electron microscopy (SEM), x-ray diffraction (XRD), thin section, and innovative techniques such as cryogenic SEM are all used to examine samples before and after testing to understand the impact of the sequence tested. These short core flood tests are informative and generate the inputs required to enable up-scaling for lateral simulation.

Laboratory testing is performed by operators worldwide to help them in decision-making during exploration,

> Operators should consider testing as a vital part of the "best practice" in selecting fluids and hardware, and as such the many types of tests being performed reflect upon the wide range of operations being performed worldwide, with each test being customised to the operator's specific needs.

development, treatment/workover, production, injection, and at any other point in the lifetime of a well where there is an opportunity to avoid or remediate damaging mechanisms. Operators should consider testing as a vital part of the "best practice" in selecting fluids and hardware, and as such the many types of tests being performed reflect upon the wide range of operations being performed worldwide, with each test being customised to the operator's specific needs. Some areas where there have been recent innovations in laboratory testing at Corex include:

Heavy oil

With the current (and future) emphasis on non-conventional reserves, traditional testing techniques can struggle to adequately represent heavy oil reservoirs. Specialist sample preparation techniques have allowed the core samples to be prepared in a manner that does not impact on their integrity, for example avoiding removal of oil cement which can create unconsolidated and unrepresentative samples. Improvements and innovations in geological techniques have also allowed for visualisation of pore-lining and pore-filling fluids without impacting on the integrity of the samples.

HPHT

High pressure, high temperature (HPHT) reservoirs, particularly tight gas, have also historically proved challenging to perform representative testing upon. Useful testing is especially vital in these fields, as any damaging mechanism can have a significant impact on permeability, and therefore the economic viability of a field. Identifying and avoiding damage before it occurs is essential in HPHT testing, and the testing

needs to be performed at meaningful temperatures and pressures; the main innovation here is the design of equipment at Corex that allows wellbore operational testing to be carried out at temperatures of over 200°C including (if required) humidification of gas at reservoir temperature.

SRA of injection operations and production drawdown operations

Scale Risk Assessment (SRA) which can range from prediction to squeeze design, Corex independently evaluate scale formation and inhibitor selection. Utilising state of the art laboratory equipment and methodologies in combination with expert post test geological sample evaluation, scale inhibitor chemicals are evaluated for formation damage mechanisms. Inhibition life time is measured in the laboratory and optimised for field squeeze application

High-rate gas

On the other end of the spectrum to tight gas is high-rate gas, which has also posed problems in the past in terms of accurate control and measurement of rate over a large range of pressures. Corex have recently designed equipment that refines this to a level never before seen in reservoir conditions testing

Assessment for Halite rich reservoirs and well operations

Specialist Cryogenic SEM analysis techniques and preparation as well as integration with modelling criteria will assist in the assessment of well operations for Halite rich injection or production intervals. Full wellbore fluid sequences are simulated under reservoir conditions (pressure and temperature) to closely mimic those of the reservoir in question, thus accurate representation. Damage mechanisms (such as precipitation or dissolution) can be identified which will specifically address the changes in equilibrium experienced with Halite rich intervals.

Conclusion

To conclude, formation damage testing is highly sensitive to the techniques and equipment used. It is vital that each test meets its objectives, so having flexibility in procedures could be viewed as more meaningful than having a "standard" procedure that provides comparable results that do not necessarily relate to field conditions. It is relatively easy to perform low-specification formation damage testing in an unrepresentative way, but more challenging to mimic wellbore conditions closely. Formation damage test results are known to vary from laboratory to laboratory based upon equipment, procedures, and parameters used, so it is important to consider the capability of the laboratory when interpreting results or putting them into context.

These examples of "challenging" scenarios help demonstrate that, if the tests and equipment are properly designed and implemented, and results are fully interpreted, independent laboratory testing can significantly reduce risk in operational decisions.

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Technical Program

Session 1 Monday, April 9 Hall-A

Petrophysics And Formation Evaluation (1) 08:00-09:30

Session Chairpersons: Scot Bittner, Schlumberger
Rami BinNassir, Saudi Aramco

8:00 – 8:15	Invited Speaker	
8:15 – 8:40	SPE-SAS-283	The Impact Of Mud Logging In Gas Reservoir Evaluation *Felix Omokaro, Saudi Aramco*
8:40 – 9:05	SPE-SAS-321	Layers Contribution In A Multi-Layered Gas Reservoir *Malik Alarfaj, Saudi Aramco, e.t al.*
9:05 – 9:30	SPE-SAS-268	Electrical Response of a Vuggy Rock Model at Different Frequencies *Fabrice Pairoys, Schlumberger, et.al.*

Session 2 Monday, April 9 Hall-B

Production Operations (1) 08:00-09:20

Session Chairpersons: Alla Dashash, Saudi Aramco
Nashi Otaibi, Saudi Aramco

8:00 – 8:15	Invited Speaker	
8:15 – 8:40	SPE-SAS-251	The Mechanism Of H2S And O2 Attack In Once Through Steam Generators Tubes Failures: South Oman Heavy Oil Steam EOR Case Study *Ardian Nengkoda; Petroleum Development Oman, et. al.*
8:40 – 9:05	SPE-SAS-290	Integral Pod Intake For Electrical Submersible Pumps *Mark Rooks, Saudi Aramco*
9:05 – 9:30	SPE-SAS-180	Innovative Technique To Liven Dead Wells With A Rigless Gas Lift System *Ahmed Sunbul, Saudi Aramco, et. al.*
9:30 – 9:45	Coffee Break	

Session 3 Monday, April 9 Hall-A

Unconventional Resources (1) 09.35-11.20

Session Chairpersons: Shaun Hayton, Saudi Aramco
Abdelaziz Khlaifat, Weatherford

9:45 – 10:00	Invited Speaker	
10:00 – 10:25	SPE-SAS-338	Practical Considerations For Pressure Transient Analysis Of Multi-Stage Fracced Horizontal Wells In Tight Sands *Ismail Buhidma, Saudi Aramco, et. al.*
10:25 – 10:50	SPE-SAS-245	Comparisons And Contrasts Of Shale Gas And Tight Gas Developments, North American Experience And Trends *Robert Kennedy, Baker Hughes Inc, et. al.*
10:50 – 11:15	SPE-SAS-296	A Case Study For The Application Of Type Curves For Production Data Analysis Of Shale Gas Wells With Linear Dual Porosity Behavior *Haider Abdulal Saudi Aramco*

Session 4 Monday, April 9 Hall-B

Drilling Operations (1) 09.35-11.20

Session Chairpersons: Khalifah Amri, Saudi Aramco
Derrick Zucher, Baker Hughes

9:45 – 10:00	Invited Speaker	
10:00 – 10:25	SPE-SAS-260	Casing Drilling Technology Application: Case History From Saudi Arabia *Jude Chima, Saudi Aramco, et. al*
10:25 – 10:50	SPE-SAS-324	Improved Technology Enhances Gas Production And Decreases Cost In Underbalanced Drilling While Using Coil Tubing Directional Dri *Kashif Ahmed, Baker Hughes, et. al*
10:50 – 11:15	SPE-SAS-162	Integrating Optimized Casing Exit And Solid Expandable Technologies: Bringing New Life To Dead Wells *Cliff Hogg, Weatherford, et.al.*
11:15 – 11:40	SPE-SAS-193	Stuck Pipe Best Practices – A Challenging Approach To Reducing Stuck Pipe Costs *Muhammad Muqeem, Saudi Aramco, et. al.*

11:30 – 12:30	Sponsored Luncheon
	Lunch & Prayer Break
	Luncheon Generously Sponsored By Halliburton

Session 5 Monday, April 9 Hall-A

Reservoir Engineering and Management (1) 12.30-14.00

Session Chairpersons: Ali Habbtar, Saudi Aramco
Amjad Ashri, Saudi Aramco

12:30-12:45	Invited Speaker	
12:45 – 13:10	SPE-SAS-382	Emerging Technology Transformed the Development of Thin/Tight Layers in a Giant Middle Eastern Field *Humam Ghamdi, Saudi Aramco*
13:10 – 13:35	SPE-SAS-346	Interpretation Of Well Test Data From Two Hydraulically Communicating Reservoirs *Bander Alquaimi, Saudi Aramco, et. al.*
13:35 – 14:00	SPE-SAS-302	A New Practical Approach To Evaluate Near Wellbore Formation Damage Parameters Based On Well Test Analysis For Gas Reservoir *Melvin Kome, TU Bergakademie Freiberg, et. al.*

Session 6 Monday, April 9 Hall-B

Reservoir Characterization 12.30-14.00

Session Chairpersons: Nezar Talha, Saudi Aramco
Saidi Hassani, Saudi Aramco

12:30-12:45	Invited Speaker	
12:45 – 13:10	SPE-SAS-220	Pressure-Transient Analysis: An Integral Role In Tar Identification *Meshari Al-Odah, Saudi Aramco*
13:10 – 13:35	SPE-SAS-331	Identifying New Opportunities In A Mature Reservoir: Wara Formation, Wafra Field, Saudi Arabia/Kuwait Partitioned Zone *Maria Masarik, Chevron Corporation, et. al.*
13:35 – 14:00	SPE-SAS-76	Stress Superposition Explains Fracture Patterns in Some Middle East Oil Fields *Sait Ismael Ozkaya, Independent Consultant*

14:00 – 14:15	Coffee Break

Session 7 Monday, April 9 Hall-A

Well Completion 14.15-16.05

Session Chairpersons: Ibrahim Arnaout, Saudi Aramco
Abdullah Mulhim, Weatherford

14:15 – 14:40	SPE-SAS-297	Optimization Of Down-Hole Sand Screens By Lab Studies For Saudi Aramco In Multiple Gas Fields *Majid Al-Rabeh, Saudi Aramco*
14:40 – 15:05	SPE-SAS-238	Precise Approach To Isolate Fractured Water Bearing Lower Zone In Complex Saudi Arabian Gas Well With High Temp Cement Using CT *Malik Ataur, Saudi Aramco, et. al.*
15:05 – 15:15	Prayer Break	
15:15 – 15:40	SPE-SAS-381	Interpretation Methodologies Of Fiber Optics DTS To Monitor Well And Completion Performance *Suresh Jacob, Saudi Aramco, et. al.*
15:40 – 16:05	SPE-SAS-234	Application Of Latest Generation Inflow Control Devices In Non-Horizontal Wells In India - Case Study *Parvez Khan, Baker Hughes, et. al.*

Session 8 Monday, April 9 Hall-B

Fundamentals in Fluid Flow Through Porous Media 14.30-16.25

Session Chairpersons: Hamoud Anazi, Saudi Aramco
Paul Smith, Saudi Aramco

14:15 – 14:40	SPE-SAS-376	Carbon Dioxide Sequestration: Modeling The Diffusive And Convective Transport Under A CO2 Cap *Rebecca Allen, KAUST, et. al.*
14:40 – 15:05	SPE-SAS-88	Inversion In The Transient Temperature Behavior In The Intervals Of Oil And Water Inflow. Theory And Technique For Application *Ayrat Ramazanov, Bashkir State University, et. al.*
15:05 – 15:15	Prayer Break	
15:15 – 15:40	SPE-SAS-91	Barothermal Effect In The Saturated Porous Media. Analytical Models *Ayrat Ramazanov, Bashkir State University, et. al.*
15:40 – 16:05	SPE-SAS-353	An Unexpected Behavior Of Fluids In A Two Phase System Interfacial Tension (IFT) Measurements. *Omar Almisned, KACST, et. al.*

Session 9 Tuesday, April 10 Hall-A

Reservoir Modeling & Simulation 08.00-09.30

Session Chairpersons: Walter Poquima, Saudi Aramco
Tareq Zahrani, Saudi Aramco

8:00 – 8:15	SPE-SAS-318	Assessment Of The Impact Of Reservoir Uncertainty In History-Match And Forecast Optimizations *Ahmed Sharif, Spt Group, et. al.*
8:15 – 8:40	SPE-SAS-263	Converting Detail Reservoir Simulation Models Into Effective Reservoir Management Tools Using Srm; Aramco Case Studies *Shahab Mohaghegh, West Virginia University, et. al.*
8:40 – 9:05	SPE-SAS-211	Innovative Simulation History Matching Approach Enabling Better Historical Performance Match And Embracing Uncertainty In Prediction *Emad Elrafie, Saudi Aramco, et. al.*
9:05 – 9:30	SPE-SAS-216	Decoupling Imbibition Force As The Recovery Mechanism In Simulation Model *Adly Muslumani, Saudi Aramco, et. al.*

Session 10 Tuesday, April 10 Hall-B

Petrophysics and Formation Evaluation (2) 08.00-09.20

Session Chairpersons: Ahmed Al Harbi, Saudi Aramco
Alhassan Hamidaldin, Schlumberger

8:00 – 8:15	SPE-SAS-281	State-Of-The-Art Openhole Shale Gas Logging *Javier Franquet, Baker Hughes*
8:15 – 8:40	SPE-SAS-317	Correlations Between NMR Relaxation Response And Relative Permeability From High Resolution Xray-CT Images *Tariq Alghamdi, University Of New South Wales, et. al.*
8:40 – 9:05	SPE-SAS-303	Quality Control/Quality Assurance Assessments Of Core Analysis Data From Multiple Commercial Laboratories *Maclean Amabeoku Saudi Aramco, et. al.*

9:30 – 9:45	Coffee Break

Session 11 Tuesday, April 10 Hall-A

Well Stimulation and Productivity Enhancement 09.45-11.20

Session Chairpersons: Mohammad Al Khaldi, Saudi Aramco
Zillur Rahim, Saudi Aramco

9:45 – 10:00	Invited Speaker	
10:00 – 10:25	SPE-SAS-512	Stimulation Strategies To Guard Against Uncertainties Of Carbonate Reservoirs *Malik Ataur, Saudi Aramco*
10:25 – 10:50	SPE-SAS-399	A New Viscoelastic Surfactant For High Temperature Carbonate Acidizing *Guanqun Wang, Texas A&M University, et. al.*
10:50 – 11:15	SPE-SAS-400	Improved Understanding Of Proppant-Formation Interactions For Sustaining Fracture Conductivity *Neelam Raysoni, Halliburton, et. al.*

Session 12 Tuesday, April 10 Hall-B

Advances in Improved Oil Recovery (IOR) & Enhanced Oil Recovery (EOR) (1) 09.45-11.20

Session Chairpersons: Ali Al Yousif, Saudi Aramco
Ahmed Hutheli, Saudi Aramco

9:45 – 10:00	Invited Speaker	
10:00 – 10:25	SPE-SAS-201	Enhanced Oil Recovery Using Nanoparticles *Naomi Ogolo, A Tertiary Institution; Mike Onyekonwu, A Tertiary Institution; Olafuyi Olalekan, A Tertiary Institution, et. al.*
10:25 – 10:50	SPE-SAS-398	Application Of Multivariate Methods To Optimize Further Development Of Thin Oil Zones In A Mature Carbonate Reservoir *Darryl Fischbuch,Saudi Aramco, et. al.*
10:50 – 11:15	SPE-SAS-164	Aqueous Foams Stabilized With Particles And Surfactants *Zupeng Liu, China University Of Petroleum, et. al.*

	Keynote Luncheon
	Lunch & Prayer Break
	Luncheon Generously Sponsored By Baker Hughes

12.20-14.15 Panel Discussion Main Hall

Unconventional Transformation of Our Energy Future

14.30-16.30
Poster Session

Paper No	Citation
SPE-SAS-329	Anisotropy and True Formation Resistivity Measurements with a New LWD Resistivity Sensor *Hsu-Hsian Wu, Halliburton*
SPE-SAS-61	CO2 Injection in Oil Reservoir Associated with Structural Deformation *Mohamed El-Amin, KACST*
SPE-SAS-278	Well Optimization Strategies in Conventional Reservoirs *Ghazi Ghatani, Texas Tech Universitys*
SPE-SAS-267	Exploring And Evaluating Eastern Hemisphere Proppants In Fracturing Applications *Prasad Karadkar, Halliburton*
SPE-SAS-309	Recent Developments and Challenges in Shale Gas Recovery *Olamide Arogundde*
SPE-SAS-223	A New, low corrosive fluid to stimulate wells with Carbon Steel tubular and internals *Alan Alex, AkzoNobel*
SPE-SAS-228#	Wellbore Remediation using Microemulsion Technology to increase Hydrocarbon Productivity *Qusai Drugar, Baker Hughes*
SPE-SAS-78	Coiled Tubing Best Practices in Conjunction with Multistage Completions in the Tight Gas Fields of Saudi Arabia, *Mohammed AlGhazal, Saudi Aramco*

15:00-15:15	Prayer Break

15:15-16:30	Poster Session

Session 13 Wednesday, April 11 Hall-A

Well Stimulation and Productivity Enhancement (2) 08.00-09.15

Session Chairpersons: Kirk Bartko, Saudi Aramco
Johan Daal, Halliburton

8:00 – 8:15	SPE-SAS-189	Fluid Technologies For Tight Gas Reservoir Stimulation *Tianping Huang, Baker Hughes Inc., et. al.*
8:15 – 8:40	SPE-SAS-364	The Effect Of Viscoelastic Surfactants Used In Carbonate Matrix Acidizing On Wettability *Oladapo Adejare, Texas A&M University, et. al.*
8:40 – 9:05	SPE-SAS-111	First Successful Deployment Of Temblok Chemical Plug To Stimulate Selectively Using CT In Saudi Arabia *Mohammed Alghazal, Saudi Aramco, et. al.*

Session 14 Wednesday, April 11 Hall-B

Unconventional Resources (2) 08.00-09.15

Session Chairpersons: Ahmad Baqawi, Saudi Aramco
Khalid Al Naimi, Saudi Aramco

8:00 – 8:15	SPE-SAS-246	Impact Of Shale Anisotropy On Completion Design *Safdar Khan, Schlumberger, et. al.*
8:15 – 8:40	SPE-SAS-337	Reservoir Optimized Fracturing: Higher Productivity From Low-Permeability Reservoirs Through Customized Multistage Fracturing *Thomas Finkbeiner , Baker Hughes, et. al.*
8:40 – 9:05	SPE-SAS-262	An Overview Of Emerging Technologies And Innovations For Tight Gas Reservoir Development *Rashid Khan, Saudi Aramco, et. al.*

9:30 – 9:45	Coffee Break

Session 15 Wednesday, April 11 Hall-A

New Emerging Technologies in Upstream Oil & Gas 09.30-11.10

Session Chairpersons: Dave Clark, Baker Hughes
Mikal Espedal, Saudi Aramco

9:45 – 10:00	SPE-SAS-104	High Power Laser Application For The Oil And Gas Industry: Past, Present And Future *Sameeh Batarseh, Saudi Aramco*
10:00 – 10:25	SPE-SAS-339	Real Time Database Inventory Model, KPI and Applications for Intelligent Fieds *Farooq Khan, Saudi Aramco, et. al.*
10:25 – 10:50	SPE-SAS-63	Upstream Data Standards At Saudi Aramco *Majid Alshehry, Saudi Aramco*
10:50 – 11:15	SPE-SAS-372	The Implication Of State-Of-The-Art Technologies Into Oilfields Karam Yateem Saudi Aramco

Session 16 Wednesday, April 11 Hall-B

Heavy Oil 09.30-11.10

Session Chairpersons: Majid Otaibi, Saudi Aramco
Bader Harbi, Saudi Aramco

9:45 – 10:00	SPE-SAS-311	Heavy Oil Testing And Flaring Solutions *Abdullah Al-Dabil, Schlumberger, et. al.*
10:00 – 10:25	SPE-SAS-367	Environmentally Safe Emulsion System: An Effective Approach For Removal Of Asphaltene Deposits *Lalit Salgaonkar, Halliburton, et. al.*
10:25 – 10:50	SPE-SAS-241	A Review Of Surfactant Affinity Difference Based On Model And Laboratory To Optimize Chemical EOR: Case Study *Ardian Nengkoda, Petroleum Development Oman*

11:30 – 12:30	**Keynote Luncheon**
	Lunch & Prayer Break
	Luncheon Generously Sponsored By Company (Company Logo

Session 17 Wednesday, April 11 Hall-A

Drilling Operations (2) 13.00-14.40

Session Chairpersons: Bandar Malki, Saudi Aramco
Qusai Darugar, Baker Hughes

12:30-12:45	SPE-SAS-195	Characterization And Stabilization Of Colloidal Gas Aphron Based Drilling Fluids: A Comparative Experimental Study *Mojtaba Pordel Shahri, University Of Tulsa, et. al.*
12:45 – 13:10	SPE-SAS-210	Drilling Agitator Tool: Effective Friction Breaking In Horizontal Applications *Assaad Mohanna, National Oilwell Varco, et. al.*
13:10 – 13:35	SPE-SAS-276	How Advances in Technology can Help Safely Abandon Off-Shore Exploratory Wells in the Arabian Gulf Region *Muhammad Haq, Weatherford*
13:35 – 14:05	SPE-SAS-187	Cementing Stage Tools Field Application Analysis – Saudi Aramco Experience *Muhammad Muqeem , Saudi Aramco, et. al.*

Session 18 Wednesday, April 11 Hall-B

Advances in Improved Oil Recovery (IOR) & Enhanced Oil Recovery (EOR) (2) 13.00-14.40

Session Chairpersons: Sultan Al Enezi, Saudi Aramco
Saad Mutairi, Saudi Aramco

12:30-12:45	SPE-SAS-240	Molecular Design Synthesis And Simulation On A Novel Gemini Surfactant For EOR From Low Permeability Reservoirs *Heng Wei, KAUST*
12:45 – 13:10	SPE-SAS-387	Dependency Of Remaining Oil Saturation On Wettability And Capillary Number *Kumuduni Abeysinghe, International Research Institute Stavanger, et. al.*
13:10 – 13:35	SPE-SAS-188	Technologies For Monitoring Matrix Oil Saturation For TA-GOGD *John Edwards, Schlumberger, et. al.*

14:00 – 14:15	Prayer & Coffee Break

Session 19 Wednesday, April 11 Hall-A

Production Operations (2) 14.55-16.10

Session Chairpersons: Noel Ginest, Saudi Aramco
Mohamed Soliman, Saudi Aramco

14:15 – 14:40	SPE-SAS-122	Coil Tubing Fill Cleanout Implemented On Plugged Stand Alone Screens: Highly Successful Campaign In Saudi Arabian Gas Producers *Murtadha Altammar, Saudi Aramco, et. al.*
14:40 – 15:05	SPE-SAS-273	Multiphase Drag Reducing Agents To Increase GOSP Production In Offshore Saudi Aramco: Field Application *Nami Al Amri, Saudi Aramco, et. al.*
15:05 – 15:30	SPE-SAS-207	Sensible Energy Savings by Enhancing Design Practices of Water Injection System *Jose Bernedo, Saudi Aramco, et. al.*
15:30 – 16:00	SPE-SAS-372	A Step Change in Fishing Efficiency: Recovering Stuck BHAs Using the Fishing Agitation Tool *Assaad Mohanna, National Oilwell Varco, et. al.*

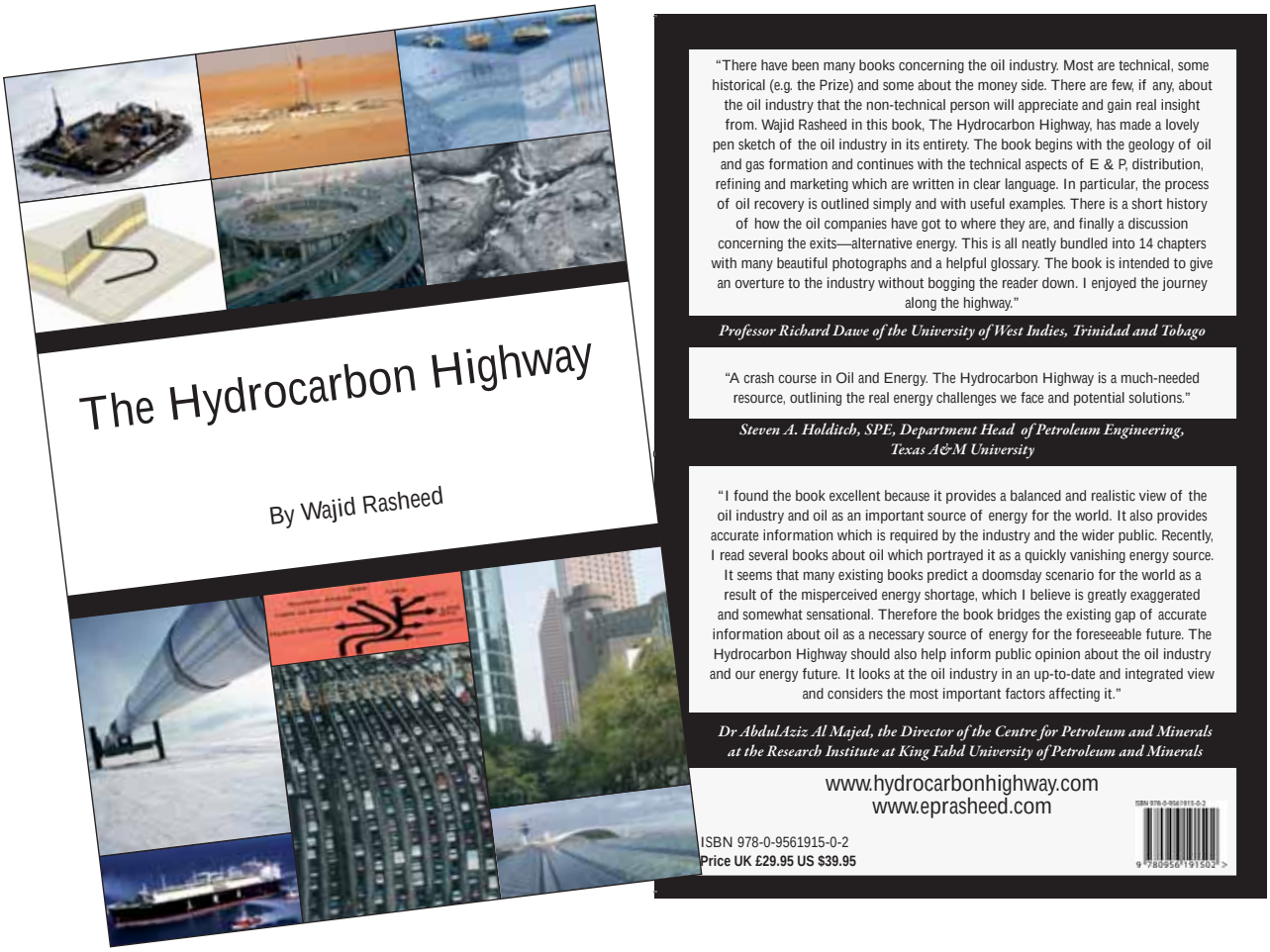
Session 20 Wednesday, April 11 Hall-B

Reservoir Engineering and Management (2) 14.55-16.10

Session Chairpersons: Faisal Eisa, Saudi Aramco
Ahmed Omair, Halliburton

14:15 – 14:40	SPE-SAS-219	Detecting Inter-Reservoir Communication Between Two Stacked Reservoir Through Integrated Field Data *Nawaf Sayedakram, Saudi Aramco, et. al.*
14:40 – 15:05	SPE-SAS-140	Formation Damage Due To Asphaltene Precipitation & Deposition During Miscible Hydrocarbon Gas Injection; An Experimental Approach *Fahad Syed, The Petroleum Institute, et. al.*
15:05 – 15:30	SPE-SAS-410	Forecasting And Monitoring Water Cut Utilizing ESP Pump Discharge Pressures And Fluid PVT Analysis *Sultan Al Enezi, Saudi Aramco, et. al.*
15:30 – 16:00	SPE-SAS-308	A Pressure Transient Approach for Dynamic Characterization of a Mature Carbonate Giant Middle Eastern Oil Field *Styg Lyngra, Saudi Aramco, et. al.*

What's in a Wet Barrel?



This chapter reveals how oil and gas asset production can be maximised through an understanding of petroleum and reservoir types.

When crude oil first came into large-scale commercial use in the 19th century, it was stored and shipped in wooden barrels with one barrel equal to 42 US gallons or 159 litres. The term 'wet' barrel denotes a physical barrel of oil that is actually delivered or consumed as opposed to a futures or other paper barrel that is traded. Asphalt, bitumen and crude are common terms describing different forms of petroleum that can be found in a typical 'barrel' of oil[1].

The term comes from the Latin petra – "rock" and oleum – "oil". For lay people, petroleum itself is

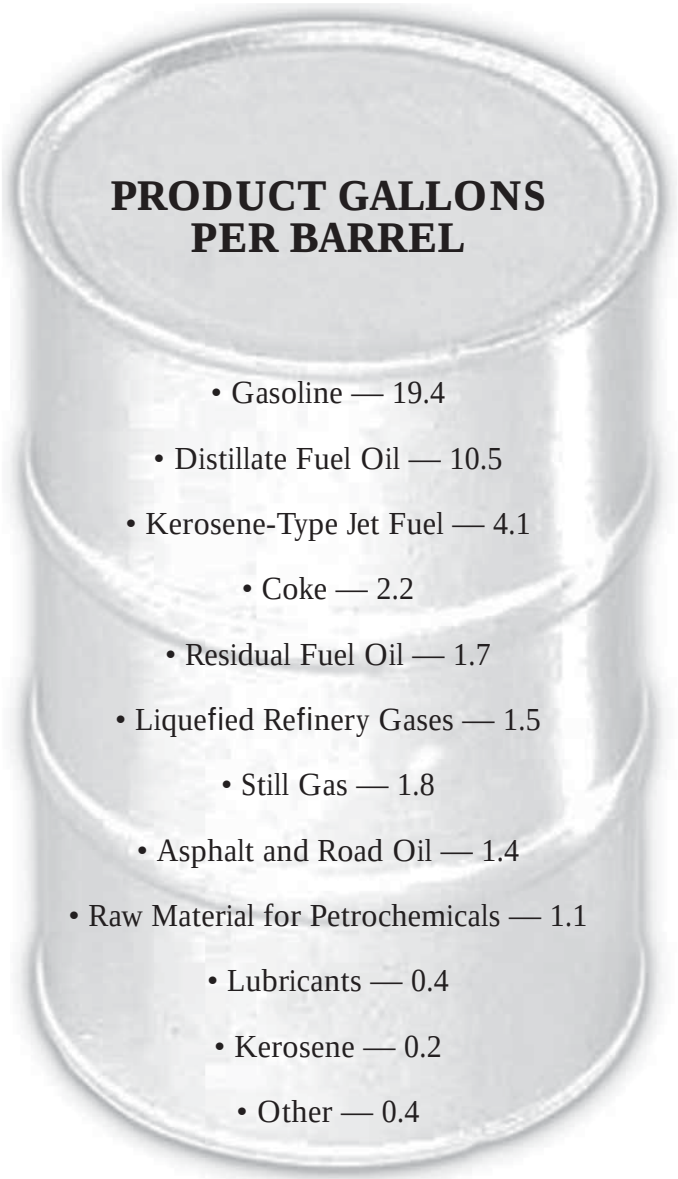


Table 1 - Products Per Barrel of Oil (in Gallons).

Note: Distillates includes both home heating oil and diesel fuel. Residual fuel oil refers to heavy oils used as fuels in industry, marine transportation, and for electric power generation. Figures are based on average yields for U.S. refineries in 2005. One barrel contains 42 gallons of crude oil. The total volume of products made is 2.7 gallons greater than the original 42 gallons of crude oil. This represents Âprocessing gainÊ (After API)

Figure 1 - Nature's Best Is Sweet and Light (EPRasheed)

Figure 2 - Heavy Oil Is Unable to Flow at Atmospheric Conditions (EPRasheed)

a generic term that covers all naturally occurring hydrocarbons as well as refined products or derivatives.

For purists, however, petroleum refers to chemical compounds made up of hydrogen and carbon atoms; consequently, the classification hydrocarbon is more appropriate. Definitions aside, hydrocarbons in their 'un-produced' state are found in underground accumulations or reservoirs of oils, gases, water and impurities located at depths ranging from 2,000 ft (610 m) to 25,000 ft (7620 m). Petroleum naturally seeps to the earth's surface along faults and cracks in rocks gathering in tar, asphalt, pitch or bitumen lakes. Shortly, we will consider the make-up of reservoirs but first of all, what's in a barrel of oil?

Nature's best orange juice is sweet and light, as is its crude; however, not all of the 200 or so naturally occurring varietals of crude oil are so blessed and this affects their commercialisation. Sweet crude has less than 0.5% sulphur content – increase this figure and it turns 'sour'. Light crude has a density of 20° or more using the American Petroleum Institute's (API) specific gravity scale and has light hydrocarbon fractions. Heavy crude has more complex fractions with higher densities and lower API gravities[2].

The Colour of Oil

Generally speaking, the colour of crude oil intensifies with its density and viscosity. While black oil is hard-to-pour and has high density and viscosity, green to yellow oils are runny and have low density and viscosity. The term 'crude' refers to petroleum straight from the wellhead in its 'unrefined' state that can generally flow in atmospheric conditions. Where petroleum is unable to flow in atmospheric conditions, it is often referred to as heavy oil, tar or bitumen[3].

Technologists quibble on when crude gets heavy; some say this happens at 25°API or less and others say 20°API or less. This is important because heavy oil trades below its lighter counterpart. For our purposes, the definition of heavy oil is 20° API or lower and further detail is found in *Chapter 8: Extreme E & P*. Finding heavy or light crude oil depends entirely on the presence of cap rock and permeability, as these will prevent or permit oil and gas to leak to the surface and be dispersed. In Venezuela's Orinoco Belt, for example, heavy oil deposits are found close to the surface with the lighter fractions of oil having migrated or dispersed over the years, leaving only the heavier residue.

Sour as a Skunk

Sour crude with its high sulphur content sells below its sweet counterpart – the gap can be US $5 or more and is likely to increase in the future. The gap exists because sour crude requires specialised refining treatment before it can be sold; however, there are more sweet than sour refineries worldwide. Consequently, a refining preference for sweeter crude exists[4].

The naturally occurring sulphur compounds or 'mercaptans' present in sour crude are powerfully smelly and are also found in garlic oils and skunk secretions. The malodorous mercaptans are by-products of decaying organic matter and they must be treated which adds to refining costs; however, mercaptans have a market value. They are used to imbue an odour to commercial natural gas so the general public can easily be alerted to a gas leak. Untreated natural gas is odourless, and

Component	Boiling Point °C	Black Oil	Volatile Oil	Gas Condensate	Wet Gas	Dry Gas
Methane, CH_4	-161	49.0	64.0	86.0	87	96.0
Ethane, C_2H_6	-88	2.8	8.0	4.4	5	2.8
Propane, C_3H_8	-42	1.8	4.5	2.4	5	0.3
n-Butane, C_4H_{10}	-1	0.8	2.0	0.8	0.6	0.2
i-Butane, C_4H_{10}	-11	0.8	2.1	1.0	0.6	0.2
n-Pentane, C_5H_{12}	36	0.7	1.5	0.3	0.5	0.1
i-Pentane, C_5H_{12}	27	0.5	1.5	0.5	0.5	0.1
n-Hexane, C_6H_{14}	69	1.6	1.4	0.6	0.3	0.1
Colour of liquid at surface		black	brown	straw	white	-
Liquid Specific Gravity		0.853	0.779	0.736	0.758	none
°API		20-35	38-50	50-70	50-70	none
GOR scf/bbl		50-1500	2000-40,000	3000-18,000	>100,000	none

Table 2 - Crude Oil and Natural Gas Varietals, After Professor Richard A. Dawe

without the tell-tale smell of the mercaptan additive, the public could be unaware of a gas leak until it was too late and someone was asphyxiated or an explosion occurred. Getting rid of sulphur, water, chlorides and other such impurities improves quality, increases value and stretches the world's oil reserves but it also adds to cost.

Table 2 shows a series of oil and gas compounds and their respective molecular weights and common names ranging from methane gas (CH_4), petrol (C_5H_{12} to C_7H_{16}) to asphaltene ($C_{80}H_{160}$). Many characteristics such as density, viscosity and flammability are determined by molecular weights and greater detail is available in *Chapter 11: Refining*.

The range of oil varietals is illustrated by extremely light oil, which has a relative density and viscosity below that of water, to extremely heavy oil which has a relative density close to that of water and high viscosity that can be 100 to 100,000 times that of water.

Molecular Weight

Typically, oil has a carbon content of 84 to 87% weight and a hydrogen content of 11 to 14% by weight[6].

Table 2 shows that hydrocarbons exist with varying densities and viscosities. Viscosity is a prime determinant of the ability to produce and refine oil. It is worth noting that the number of hydrocarbon compounds increases dramatically due to isomers, differing arrangements of the same number of atoms. In the case of hexane (C_6) there are five isomers, for decane (C_{10}) there are 75 and for C_{30} there are more than four billion. Although laboratory analyses of reservoir hydrocarbons can profile all compounds containing as many as 20 carbon atoms, it is usually sufficient to profile compounds containing up to six or seven atoms, with a general number being used to represent the total proportion of heavier molecules that are present[7].

The general trends depend on the ratios of methane (CH_4) and the heavier components. The intermediates, C_2-C_6, control the GOR and API grade. The percentages shown are representative only and each category can be considered as flexible. Additionally, once production starts from a reservoir, the state of equilibrium that has been established over geological time is destroyed. Pressure gradients are created and the chemical composition and the physical properties of the fluids in the reservoir change. This happens as the pressure exerted on the fluids changes from the reservoir to the wellbore to the surface and, over time, as the fluids constituting the reservoir change.

Analysis is usually presented in terms of C_1, C_2, C_{n+} with n often being 7, 12 or 20. Compounds that are not

Figure 3 - Checking Crude Samples (Saudi Aramco)

expressed in this way are usually treated as a composite fraction characterised by a molecular weight, density and/or a boiling point.

For E & P purposes, physical properties such as colour, API grade, viscosity, bubble point pressure, Gas-Oil Ratio (GOR), pour-point, and kerosene content are characterised. For downstream purposes, actual hydrocarbon compositions and fraction descriptions are required. Traditionally, the analysis of produced fluids was performed in the laboratory and could take weeks or more to obtain. Nowadays, real-time formation testing tools can provide analysis of produced fluids in near real-time at the wellsite.

Saturated Oil

Produced oil will always contain a certain amount of dissolved gas. The exact amount depends on reservoir conditions such as temperature and pressure as well as the composition of the oil. If the oil cannot dissolve any more gas under the prevailing conditions, it is termed saturated; the excess gas has moved to the top of the reservoir and formed a gas cap. If the oil can dissolve more gas, it is termed undersaturated, and no gas cap will be initially present on production. The GOR is the ratio of the volume of gas produced to the volume of liquid and may be expressed as cubic feet per barrel depending on the units used for measuring gas and liquid. For gas wells, the inverse ratio is sometimes used and the liquid-gas ratio is expressed in barrels per million m^3 (or million cubic feet)[8].

Impurities

Reservoir characteristics depend on the interplay between the molecular arrangements of the hydrocarbons, the extent of liquid and gas phases as well as the existence of impurities. Aqueous impurities are caused by differing levels of salinity and mineral salts within water that were present within rock pores before hydrocarbons migrated into the reservoir rock, displacing a certain volume of this water. The volume of water that remains after migration is known as 'connate water' and it is common for large volumes of water to be produced in conjunction with oil and gas.

Water

Water is present at all stages of oil production. Connate water found in the reservoir at discovery can occupy 5 to 50 % of the pore volume and it is common for large volumes of water to be produced in conjunction with oil and gas (it is not always the case that a reservoir has reached maturity simply because it is producing water.

> Water is nearly always present in gas reservoirs and reservoir gas is often substantially saturated with water vapour at the temperature at which it enters the wellbore.

See *Chapter 9: Mature Fields* – Water Management). It is also usually very salty, often more concentrated than seawater. Levels of water saturation can be accurately measured by well-logging, surface monitoring as well as permanent downhole monitors. Water breakthrough causes production problems including corrosion and scale, particularly as reservoir water often contains salts up to 250,000 mg/l, in comparison to sea water which contains 35,000 mg/l of salts.

Water and oil also create emulsions which are difficult to break and disposing of produced water can generate an environmental burden as it must be disposed of adequately. Further, any incompatibility between injected water and connate water can create chemical scale[9].

Water is nearly always present in gas reservoirs and reservoir gas is often substantially saturated with water vapour at the temperature at which it enters the wellbore. With the change in temperature and pressure from the subsurface to surface, the gas will not be able to hold as much water and it will condense both within the well during the upward travel of the gas and in surface equipment. Much of this condensed water is carried in the flow lines into the separator as entrained droplets. Water can form hydrates with natural gas, which can create production difficulties, rendering metres and valves inoperative and, on occasions, causing disasters. Low temperature separators are needed to remove the entrained water close to the wellhead before the gas arrives at trouble points. In many cases, appreciable amounts of water will settle to the bottom of the well and can, in time, saturate the zone surrounding the wellbore so that the permeability to the flow of gas may be materially reduced. This reduction can result either from water blocking or clay swelling and can be responsible for a gradual decrease in deliverability and periodic remedial work-overs[10].

Other impurities can be metallic such as vanadium or non-metallic such as hydrogen sulphide (H_2S). If there is any measurable sulphur content (more than one part per million), then the sulphur components, H_2S, can cause considerable damage to the production facilities unless they are designed to handle sulphur. The sulphur components are also poisonous to humans hence lowering the commercial value of the oil or gas. They therefore have to be extracted, but can be converted to sulphur and sold on as a useful product. The production equipment has to use special quality steels to prevent rapid corrosion. Getting rid of sulphur, water, chlorides and other such impurities improves quality, increases value and stretches the world's oil reserves but it also adds to cost[11].

Releasing Hydrocarbons

The production of underground hydrocarbons is based on the release of trapped and pressurised fluids. Production involves a reduction in pressure

> The point at which natural gas components start to condense out of the gaseous system is known as the hydrocarbon dew-point and refers to the temperature (at a stated pressure) at which this occurs.

and temperature from downhole reservoir conditions to atmospheric or surface conditions. As a result, hydrocarbons originally present as only liquid underground will separate into liquid and gas on their way to the surface, as soon as well pressure declines below the 'bubble point'.

In a mixture of liquids, the bubble point occurs when the first bubble of vapour is formed. For single component mixtures, the bubble point and dew point are the same and are referred to as the boiling point.

Hydrocarbons originally present as gas underground will generally produce some liquid at the surface due to condensation, which occurs when the pressure and temperature are reduced. The point at which natural gas components start to condense out of the gaseous system is known as the hydrocarbon dew-point and refers to the temperature (at a stated pressure) at which this occurs. Both bubble point and dewpoint are useful data when designing distillation refinery systems.

Surface facilities will mechanically separate gas from liquid using gravity separators or de-gassing facilities after which the volumes of liquid and gas are measured separately.

Gas

Natural gas volumes are reported in standard cubic metres [(s)m^3] or standard cubic feet (scf). Quantities of natural gas are usually expressed in cubic feet; a cubic foot is equivalent to approximately 0.028 m^3 at standard conditions[12]. For reserves valuation, gas is usually expressed in thousands (10^3) of cubic feet (Mcf), millions (10^6) of cubic feet (MMcf), billions (10^9) of cubic feet (BCF) or trillions (10^{12}) of cubic feet (TCF).

Methane is the most abundant component of natural gas and has numerous fuel applications. These range from liquefaction, compression, and Gas to Liquids (GTL). For further details, see *Chapter 13: Renewable Energy*. The second largest component is ethane which can be liquefied and sold as fuel, but is mostly used as a petrochemical feedstock. Propane and butane are also found in natural gas, albeit in smaller amounts, and are commonly separated and sold as Natural Gas Liquids (NGLs). This commercial value stems from their comparatively high-energy content. On a cubic

foot basis, methane renders just over 1,000 Btu, while propane renders 2,500 Btu and butane 3,250 Btu[13].

Gas Condensate

Gas condensate or 'wet-gas' reservoirs are an important class of hydrocarbon accumulation and describe hydrocarbons which are gaseous in the underground reservoir. When the temperature and pressure of gas condensate are reduced to dew point, however, they partially condense to yield liquid condensate. Condensates are often characterised by low-density and high-API gravity (45° and above) and co-exist with natural gas.

Natural gas condensate is typically composed of pentane, hexane, heptane and octane. Liquids that condense are almost transparent or light yellow and can be refined in a way similar to very light crude oil[14].

Condensate-bearing reservoirs pose further production challenges due to the effect changes in reservoir pressure have on the hydrocarbons. Gas may be converted to liquid if its pressure drops below the dew point during production. If gas is preferable to liquid production, reservoir pressure can be maintained by fluid injection. Reservoir fluid composition determines:

- Fluid type—dry gas, condensate gas, volatile oil, black oil
- Method of fluid sampling, laboratory tests
- Surface equipment (type and size)
- Calculation procedures for determining oil and gas in place
- Techniques for predicting oil and gas reserves
- Prediction methods for future production rates, and
- Depletion plan and secondary or enhanced oil recovery methods.

Common Types of Petroleum

There are several common types of petroleum:

Associated Gas: Is the natural gas and NGLs, which under reservoir conditions, are dissolved in the crude oil or are present as a gas cap above the oil in the reservoir.

Condensate or Distillate: Is the pale straw-coloured liquid with an API of 45° to 75° produced at surface from hydrocarbons which were originally gas or liquid in the reservoir. The term is often loosely applied to any liquid produced at the separator from light volatile oil or gas fluids.[15]

Conventional Black Oils: Are the most common reservoir liquids. They have: a viscosity low enough to flow naturally into a well; gravities that are usually between 20° API to 45° API; GORs ranging from 100-2000 scf/stb (20-360 m^3/m^3); specific gravity from 0.6 to 1.0; viscosities ranging from below 1cp; and, liquids that are about as thin as water to those that are >100 cp. They are black to green-black in colour.

Crude Oil (Oil): Is the common liquid form of petroleum produced from an oil reservoir when the gaseous constituents have been removed or have escaped and ranges from heavy tarry substances to

API Gravity (°API)	Classification	Specific Gravity (g/cc)
10° to 20°	Heavy Oil	1.0 to 0.93
20° to 30°	Medium Oil	0.93 to 0.87
>30°	Light Oil	less than 0.87

°API = (141.5°/SG - 131.5 [SG = specific gravity at 60°F = 1.0])

Table 4 - A Rough Classification of Crude Oil Is Sometimes Used Based on API Gravity

> It is this diversity, along with variations in pressure, temperature, depth, thickness, sealing faults and potential links to adjacent reservoirs, that leads to oil and gas accumulations being characterised as uniquely different or heterogeneous structures.

conventional oil. Most petroleum liquid products and crude oils are lighter than water and their weight is often expressed in degrees (°) API.

The higher the number of API degrees, the lighter the oil. An API rating of 46° for a crude would mean that it is super light. Heavy oil would have an API of 18° to 20° degrees. The commercial value of oil varies according to its specific gravity; heavy oil trades at a lower value, i.e. less than 20° API trades at a lower value (US $5-10) to lighter oils, i.e. from 20° API to 45° API. Above 45° API, oil is considered superlight and has a progressively higher value (US $15 or more).

Gas Condensates: Condensates that are straw coloured and usually have a specific gravity above 45° API. The distinction between gas condensate, volatile oil fields and gas fields is important in practice as the reservoir may require different production and commercialisation strategies as discussed in *Chapter 11: Refining.*

Heavy Oil: Is so viscous that it does not flow easily into a well and has a gravity below 20° API and a viscosity above 20 cp as well as extremely low (negligible) production rates which often include large quantities of loose sand.

Natural Gas: Is a mixture of hydrocarbons consisting mainly of methane but also including ethane and minor quantities of NGLs.

Natural Gas Liquids (NGLs): Light hydrocarbons consisting mainly of propane and butane, which are liquid under pressure at normal temperature.

Oil Sands: Refers to heavy black tar (similar to bitumen) which is frequently mixed with high volumes of sand. They are found principally in Canada and Venezuela. Oil Sands require mineral extraction production akin to mining which is completely different to oil and gas well production.

Volatile Oils: Oils that have low specific gravities and viscosities, 45°-70° API and GORs in excess of 360/m^3 (2000 scf/stb). They are pale red to brown in colour[16].

Although the above nomenclature for hydrocarbon accumulations is useful, it should be appreciated that reservoirs do not follow strict definitions and have

> "... the poor correlation between porosity and permeability, and the presence of caverns and fractures, create very complex paths for fluids, making it difficult to accurately model the distribution of permeability in carbonate reservoirs."

been found to produce hydrocarbons in almost every conceivable ratio. Additionally, variations in pressure and temperature mean that there are no clear divisions between the classes of reservoirs.

For our purposes, production mainly depends on the physical properties and behaviour of the reservoir fluids which change once production has commenced. Those changes will depend on what is in the reservoir.

What's In a Reservoir?

Reservoirs have been found to produce almost every conceivable ratio of hydrocarbons. It is this diversity, along with variations in pressure, temperature, depth, thickness, sealing faults and potential links to adjacent reservoirs, that leads to oil and gas accumulations being characterised as uniquely different or heterogeneous structures. Carbonate reservoirs are considered highly heterogeneous. Calcium carbonate is much more chemically active than the silica that constitutes sandstones. It is easily dissolved in water, even more so in acidic water. Mechanical properties are another significant difference. Carbonate rocks tend to be more prone to fractures than sandstones. For all these reasons, carbonates form different rock types with a heterogeneous distribution throughout the reservoir. Moreover, the poor correlation between porosity and permeability, and the presence of caverns and fractures, create very complex paths for fluids, making it difficult to accurately model the distribution of permeability in carbonate reservoirs[17].

Consequently, the challenge for the oil company is how best to produce a particular oil and gas accumulation considering all these factors and simulating their interaction over time.

Reservoir Fluid States

Reservoirs are found at depths varying from 2,000ft+ (610 m) to deeper than 25,000ft+ (7,620 m). As noted in *Chapter 1: The Origin of Oil—Migration*, it is known that heavy oil is usually found in shallow reservoirs while lighter oil is found in deeper reservoirs, with gas alone found in the deepest reservoirs. Pressure and temperature conditions vary between reservoirs. Shallow reservoirs often have near standard conditions (15°C [59°F] and 15 psi [1 bar]) while deep reservoirs may have temperatures above 250°C (482°F) and pressures that may exceed 20,000 psi (1378 bar). Reservoir fluid states are held in a complex rock-

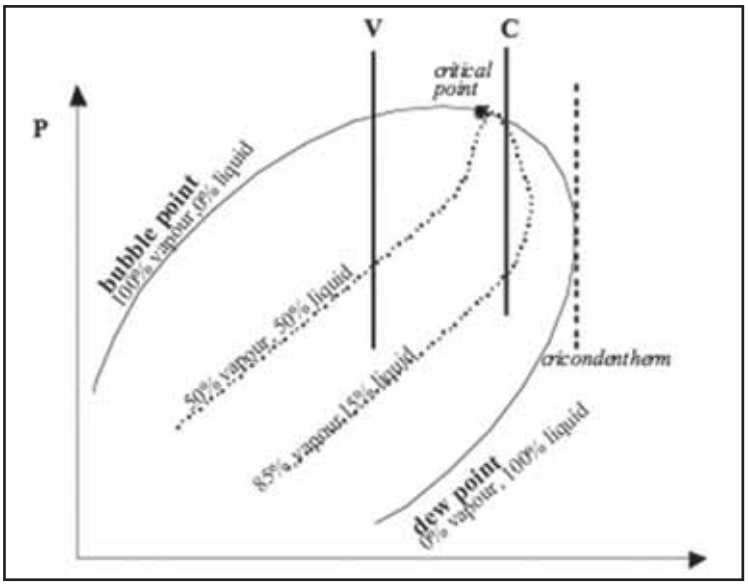


Figure 4 - Cricondentherm, After Professor Richard A. Dawe

gas-liquid system and can exist as aqueous and non-aqueous states or multi-phase immiscible fluids[18].

We have seen that hydrocarbons occur in unique ratios and diverse states. The same can be said of reservoirs. Reservoir engineers must have a thorough understanding of this heterogeneity, as this plays an important part in understanding how production should best be engineered. Physical properties are needed to accurately describe fluid pressures up to 1,500 bar (22,000 psi), the possibility of high temperatures (up to 250°C) and corrosive fluids (waters that contain more salt than seawater i.e. approximately 35,000 mg/l). Empirical data and laboratory modelling is often applied to field reservoir applications.

Depending on the oil and gas accumulation, and its reservoir pressure and temperature, hydrocarbons underground may be present initially as:

- Liquid only – oil reservoir
- Gas only – gas or gas/condensate reservoir, or
- Gas overlying liquid – oil reservoir with gas cap, or gas reservoir with oil ring.

The comprehension of such complex natural fluids comes from an understanding of simple and ideal systems, which are modelled in the laboratory. The data required includes: density; compressibility; formation volume factors and gas-oil ratios for determination of recovery factors; viscosity and gas-oil ratios for production rates; and interfacial tension for recovery efficiency, as it has a major influence on oil trapping. See *Chapter 1: Origin of Oil -Trapping Mechanisms*.

The Phase Behaviour of Hydrocarbons

As reservoir pressure drops, the resultant behaviour of the hydrocarbons depends upon the temperature and differential pressure as well as the composition of the hydrocarbons.

As pressure drops, gas expands and liquids tends to vaporise to gas. This is because molecules can move apart through their own kinetic energy breaking the weak bonds that hold them. (See *Chapter 11: Refining – Van der Waals Forces*). Conversely, if pressure is increased, molecules are forced closer together so that gas is compressed and forms a liquid. These changes from gas to liquid and vice versa are known as phase changes and are termed normal behaviour. Understanding this Pressure-Volume-Temperature (PVT) behaviour is essential because it controls the entire oil production process, while the physical parameters are needed to determine the process efficiency and sizing of facilities.

Multi-Component Mixtures

The behaviour of multi-component hydrocarbons presents greater complexity due to the different volatilities of the components involved. Consequently, vapour and liquid have different compositions when in equilibrium. As the pressure drops, the compositions of both the liquid and gas phases change continuously:

Figure 5 - GOSP In The Shaybah Field Saudi Arabia (Saudi Aramco)

the first gas appears at the bubble point and only liquid remains at the dew point. One consequence of this behaviour is that the pressure-temperature plot is no longer a simple curve as for the single component; instead it is an 'envelope' – see Figure 4.

The maximum pressure defined by this envelope is known as the cricondenbar; above it, the liquid and gas phases cannot co-exist. The maximum temperature defined by the envelope (the cricondentherm) is, likewise, one above which the two phases cannot co-exist. The critical point is the point in the envelope at which the properties of the gaseous and liquid phases become identical – it is not related in any simple way to the cricondenbar or the cricondentherm.

The behaviour of the fluid as it leaves the reservoir (essentially an isothermal environment) and travels through the production tubing and wellbore to the separation facilities requires more complex considerations of the thermodynamic behaviour; however, simple laboratory measurements are sufficient for design calculations[19].

If the reservoir pressure is at the bubble point, the oil is said to be saturated. If the reservoir pressure is above the bubble point, the oil is said to be undersaturated. An oil reservoir which is discovered with a gas cap is at its bubble point and is, therefore, saturated. An oil reservoir that is unsaturated describes hydrocarbons above their bubble point, where the reservoir temperature is substantially below the critical point and surface GORs are low to moderate. On production, as the reservoir pressure drops, gas comes out of the solution (solution gas drive). The first gas liberated is composed principally of the lightest components (methane, ethane and propane) as they possess the highest molecular energy and the lowest molecular attraction for other molecules.

Vaporisation of the lighter components is usually followed by quantities of heavier components until at low pressures only a fraction of the original material remains liquid. Gas has formed due to vaporisation of the light components and, as a result, the remaining liquid is described as having shrunk in volume. For a black oil, the shrinkage is only a small amount (often less than 30%). It increases rapidly, however, through the low pressure range (separator pressures) and through volumetric loss of intermediate and heavy material from the remaining liquid. Shrinkage characteristics in this range of pressures are extremely significant because surface separation of oil from gas occurs under these conditions.

Condensate Fields

A condensate field is where the reservoir temperature lies between the cricondentherm and the critical temperature. In this case, if the overall reservoir pressure is allowed to drop, liquids condense out in the formation and may be lost because their saturation is so low that no liquid flow toward the well bore occurs

Depth of Reservoir	Initial Pressure	Temperature
608m (2000')	61 bar (900 psia)	21-32ºC /70-90ºF
1520 m (5000')	153 bar (2250 psia)	38-65ºC /100-150ºF
3952 m (13000')	408 bar (6000 psia)	82-149ºC /180-300ºF

Table 5 - Reservoir Pressure by Depth

(zero permeability to liquid). In order to prevent this valuable loss by retrograde condensation and to extract the liquids, reservoir pressure is often kept above the dew point by recycling the gas that remains after surface processing. A gas (wet or dry) field is one in where the reservoir temperature is above the cricondentherm. Once the gas starts to expand up the tubing to the surface, the temperature as well as the pressure falls, and this continues to the final surface conditions. Liquid hydrocarbons may condense out in the tubing and surface lines and are often recoverable. Low-temperature separation increases the yield of these valuable light-end liquids. A dry gas field is one in which the final point (normally the separator) lies to the right of the envelope and no liquids are formed.

Crude Oil Properties

The PVT characteristics of oilfield liquids are more complicated than for gases and it is usual to distinguish between saturated and unsaturated conditions. In the former, gas starts to separate from the liquid as soon as pressure begins to drop with production. In the latter, the pressure at which gas begins to separate from the liquid is some distance below the initial reservoir pressure at the bubble point, (Pb). The rate of pressure drop in an unsaturated depletion type field can be quite dramatic with a pressure drop of perhaps 1,000 psi for a production of only one or two percent of the oil initially in place. The reservoir fluids have pressure-dependent properties. It is necessary to know how the crude will behave as the reservoir pressure drops, or other reservoir conditions are altered to be able to determine how best to: produce a particular crude-oil accumulation; to forecast attainable production rates and the ultimate cumulative production; and, to develop EOR plans for a reservoir. These properties are measured in the laboratory using samples of crude taken from the field[20].

PVT Data for Oil

Oil and gas behaviour can be described by using functions of pressure and temperature. Various parameters such as oil and gas interaction, composition and the phase envelope need to be determined for each reservoir. This is often done by laboratory testing of bottom-hole samples or, by using Repeat Formation Testing (RFT) or Modular Formation Dynamics Tester (MDT) tools. Additionally, oil and gas collected at surface may be recombined to represent the reservoir fluid as precisely as possible. This is, however, a difficult task. In many reservoirs, there are variations across the field and also between different reservoirs. Fluid sampling should be carried out as early as possible to ensure reserve calculations, well flow calculations and facilities design are based on representative samples. Great care is needed in conditioning the well to ensure that the fluid sample is representative. Generalised correlations have been developed which give information about the PVT properties for oil and dissolved gas using the available data obtained from a producing well test, e.g. oil gravity, gas gravity, producing GOR and reservoir temperature[21].

Difficulties arise from obtaining representative samples and deciding the correct thermodynamic path the fluids should follow in the laboratory to mimic the path followed by the hydrocarbons as they move through the reservoir to the well, to the surface and finally to the gauges and the stock tanks.

> In general, less gas is evolved in differential than in flash liberation, thus a greater proportion of the lighter hydrocarbons remain in liquid form when the pressure reduction follows the differential-liberation path.

The processes affecting the fluids as they flow from the reservoir to the stock tank vary, but can normally be approximated to the flash or differential process. For instance, flash liberation can simulate the process in the tubing linking the formation to the surface and in the gathering lines from wellhead to separator because the agitation of the flow keeps the two phases in contact with each other. In the surface-gas separator, the pressure on the produced fluids is suddenly dropped and the gas evolved remains, for a time, in contact with the crude, i.e. a flash liberation.

In general, less gas is evolved in differential than in flash liberation, thus a greater proportion of the lighter hydrocarbons remain in liquid form when the pressure reduction follows the differential-liberation path. For black oils, the difference is usually small, but for volatile oils it can be substantial so that two or three stage separation is needed to drop the surface pressure from that at the wellhead to atmospheric (stock-tank pressure) to get maximum liquids (perhaps 8-11% more). Determination of the number of intermediate separators (GOSP) and the pressures at which they should operate depends on oil and gas properties as well as economic considerations[22] (see Figure 5 for Gas Oil Separator Plant).

Reservoir Pressure and Temperature

In normal conditions, reservoir pressure is about equal to the hydrostatic pressure (pressure due to a column of water) measured from the surface. The hydrostatic gradient is about 0.45 psi per foot (9.6 kPa/m). Temperatures increase with depth by 10°F to 20°F per 1,000 feet (1.8-3.6°C/100m). The table shows reservoir pressures according to depth.

In overpressured reservoirs, the initial pressure may be considerably higher. If different datum corrected pressures are found in different parts of the field, particularly after some production, it is likely that the field is not totally in communication and that there are sealing faults or isolated sands[23].

Reservoir Temperature

Primary recovery methods rely on the assumption that reservoir temperature stays constant. As fluids are produced any change in downhole temperatures due to production is compensated by heat from the cap or base rocks, which are considered to be heat sources of infinite capacity[24].

Average reservoir temperatures are therefore needed for laboratory analyses reflecting reservoir conditions.

> If the field is complex, with multiple reservoirs and faulting, the most efficient well-spacing may be initially difficult to decide as each fault block may have to be regarded as separate accumulations.

Reservoir temperatures are used to determine fluid properties such as viscosity, density, formation volume factor and gas in solution. Downhole gauges (during drilling or permanent) are used to measure reservoir temperature.

If a variation in temperature is detected across a reservoir after correcting for depth, an average value can be calculated and used as a constant reservoir temperature. For EOR, involving chemical and miscible processes, changes in temperature affect both the phase behaviour of injected and produced fluids, and therefore will affect recovery. The modelling of such processes must be accompanied by laboratory tests carried out using reservoir temperatures. In EOR processes that employ heat injection, such as steam or in-situ combustion, reservoir temperatures do not remain constant. In these cases, the reservoir temperature needs to be monitored all the time so as to detect the movement of the heat front[25].

Development of an Oil or Gas Field

Once a discovery has been made, appraisal wells are drilled to determine the extent of the accumulation. The important reservoir calculations from the discovery data are the minimum size of the accumulation and the minimum size needed for commercial production. The appraisal wells are then sited to attempt to answer the question, 'Is this economic?' rather than 'How large is it?' With each appraisal well comes a refinement of the geological model of the accumulation, as represented by maps and cross-sections, and a new economic assessment. If it becomes obvious that the accumulation contains sufficient oil or gas to be considered commercial, development plans will be formulated. The siting of development wells is different from that of the appraisal wells, as now the purpose is to produce the petroleum as efficiently as possible at the lowest unit cost. If the field is complex, with multiple reservoirs and faulting, the most efficient well-spacing may be initially difficult to decide as each fault block may have to be regarded as separate accumulations. Over time production of fluids from the reservoir will change fluid pressure and flow rates. Production engineers will critically examine these factors to ensure that production can maximised over the life of the field.

This was a tough chapter but we now know what is in a reservoir and what actually constitutes a barrel of oil. What we have yet to learn is where these barrels are. Who are the 'oil haves' and 'have-nots'?

Readers note; reservoir and reservoir fluid characteristics are well covered in industry texts. Physical and chemistry texts provide the background to PVT behaviour, single and multi phase fluid flow.

References

1. Crude oil volumes are still reported in barrels and in some cases in tonnes. However, the number of barrels contained in a tonne varies according to the type and specific gravity of the crude involved. An average number would be around 7.33 barrels per ton. Surface oil is reported at stock-tank (st) conditions, with volumes in cubic metres (m^3) or barrels [stb, or (st)bbl].

2. API What a barrel of crude oil makes. API Factsheet.

3. See Petrobras Technology Harts E & P, June 2003 p 45 for heavy oil definition below 19°API.

4. TTNRG Nature's Best Wajid Rasheed.

5. Pricing differential is due to higher proportion of heavier and sourer (high sulphur) crudes that relative to light sweet production. More than half the world's produced oil is heavy and sour in quality and this proportion is expected to increase. This depends on the crude oil's molecular structure and sulphur content. The oil will be classified accordingly and priced using reference crudes. Some of the common reference crudes are: West Texas Intermediate (WTI), Brent blend from the East Shetland Basin of the North Sea. Dubai-Oman, used as benchmark for Middle East sour crude oil flowing to the Asia-Pacific region, Tapis (from Malaysia, used as a reference for light Far East oil), Minas (from Indonesia, used as a reference for heavy Far East oil), The OPEC Reference Basket, a weighted average of oil blends from member countries.

6. The compositions of different crudes are measured and published in assays. Refining engineers use assays to decide which crudes will be required to formulate products.

7. API 5 RP 44 Sampling Petroleum Reservoir Fluids Proper management of production from a natural gas or petroleum reservoir can maximize the recovery of the hydrocarbon fluids (gas and oil) originally in the reservoir. Developing proper management strategies requires accurate knowledge of the characteristics of the reservoir fluid. Practices are recommended herein for obtaining samples of the reservoir fluid, from which the pertinent properties can be determined by subsequent laboratory tests.

8. For gas wells, the inverse ratio is sometimes used and the liquid-gas ratio is expressed in barrels per million m^3 (or million cubic feet).

9. Formation, Removal, and Inhibition of Inorganic Scale in the Oilfield Environment Author: Wayne W. Frenier and Murtaza Ziauddin ISBN: 978-1-55563-140-6. See also Scale formation RP 45 Analysis of Oilfield Waters 3rd Edition/August 1998.

10. Refining costs Sulphur Corrosion Control Author: Charles Kirkley See also RP 49 Recommended Practice for Drilling and Well Servicing Operations Involving Hydrogen Sulphide Recommendations include well drilling, completion, servicing, workover, downhole maintenance, and plug and abandonment procedures conducted with hydrogen sulphide present in the fluids being handled. 2nd Edition / May 2001. Further cost is added at the refining stage.

11. The Color of Oil Economides et al. Publisher: Round Oak Publishing Company; (March 1, 2000) 220 pages ISBN: 0967724805.

12. EIA BTU fuel content.

13. See also API Manual of Petroleum Measurement Standards. This manual is an ongoing project, as new chapters and revisions of old chapters are released periodically.

14. Condensates Energy supplies are often quoted in barrel of oil equivalent (boe). The energy contained in 6000 scf (170 s m^3) of gas is about equivalent to that in one barrel of oil (0.16 s m^3), so for an oil with a gas-oil ratio of 1500 scf/bbl (266 m^3/m^3), 25% of the energy from the reservoir is contained in the produced gas. Thus for black oils about 10 % of the produced energy is in the gas, whereas for the gas condensate field about 75% of the energy is produced as gas. For this reason condensate reservoirs are not produced for the sake of the liquids only. A gas field of size 0.6 trillion scf is equivalent to an oil field of around 100 mmbbls.

15. See Advanced Reservoir Engineering Author: Tarek Ahmed and Paul McKinney ISBN: 0-7506-7733-3.

16. Saudi Arabia Oil and Gas Issue 4 The Carbonate Challenge (www.saudiarabioilandgas.com).

17. The behaviour of reservoir fluids is based on the laws of physical chemistry for perfect gases and the phase changes in gas-liquid systems.

18. The Flow of Complex Mixtures in Pipes, 2nd Edition, G.W. Govier and K. Aziz. Thirty-five years

after its first publication, remains a fundamental resource, providing a unified approach to all types of complex flow.

19. Lab Crude Samples McCabe, Warren L.; Smith, Julian C.; Harriot, Peter (2005), Unit Operations of Chemical Engineering (seventh ed.), New York: McGraw-Hill, pp. 737-738, ISBN 0-07-284823-5.

20. API 5 RP 44 Sampling Petroleum Reservoir Fluids Proper.

21. SPE 102854 Performance Appraisals of Gas/Oil Separation Plants by S. Kokal, SPE, and A. Al-Ghamdi, SPE, Saudi Aramco.

22. If the field is communication similar datum corrected pressures will be found as average reservoir pressure drops.

23. Fluid Flow & Heat Transfer In Wellbores A.R. Hasan and C.S. Kabir.

24. The properties of crude oil and hydrocarbon gases have been extensively studied over the past several decades and many useful tables and correlations can be found in prior work e.g. charts (Dawe and Bradley 1987, McCain 1990).

25. The compressibility of oil is not entirely pressure dependent. The reported density of the oil is almost always that of the stock-tank oil not the reservoir oil, although reservoir oil density varies with pressure due to the associated effect of the gas in solution, which varies with pressure.

An accurate knowledge of Pb (bubble point pressure) is important when producing a reservoir. It is the reservoir pressure below which gas comes out of solution so that production can become more complicated. Gas affects oil recovery and production rates, well performance, and vertical pressure-loss calculations.

26. The oil-formation volume factor, Bo. When the pressure is released to below Pb, gas comes out of solution. As the oil is produced the drop in pressure and temperature in the wellbore causes the oil to shrink.

27. The oil density, ro.

28. The API gravity (the equivalent oil density at stock tank conditions.

29. When the reservoir pressure drops below Pb, some gas is released from the oil in the formation. The gas-solubility factor, R, is the volume of free gas at standard conditions that is released from that volume of reservoir oil that results in a unit volume of stock-tank oil.

30. There is a great variation in oil viscosity mo, from formation oils that are thinner than water to heavy oils, having the consistency of a thick tar. The main effect of pressure (<Pb) on viscosity is that gas comes out of solution, and as the gas contains the lighter hydrocarbon molecules, the viscosity tends to increase as pressure drops.

The current version of IUPAC's standard is a temperature of 0°C (273.15°K, 32°F) and an absolute pressure of 100 kPa (14.504 psi).

Standard Conditions are generally 15°C and 1 atmosphere (or sometimes 1 bar) or 60°F and atmospheric pressure (14.7 psi).

Natural gas volumes are reported in standard cubic metres [(s)m^3] or standard cubic feet (scf). Quantities of natural gas are usually expressed in cubic feet; a cubic foot is equivalent to approximately 0.028 m^3 at standard conditions. However, for reserves valuation, gas is usually expressed in thousands (103) of cubic feet (Mcf), millions (106) of cubic feet (MMcf), billions (109) of cubic feet (BCF) or trillions (1012) of cubic feet (TCF).

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