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2012 – Issue 29

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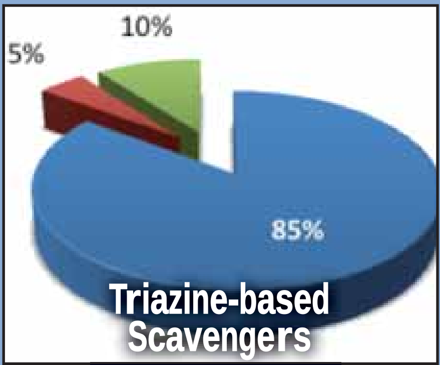

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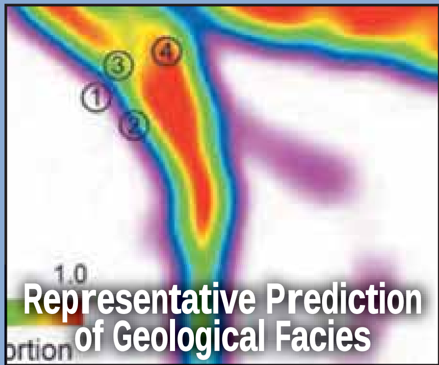


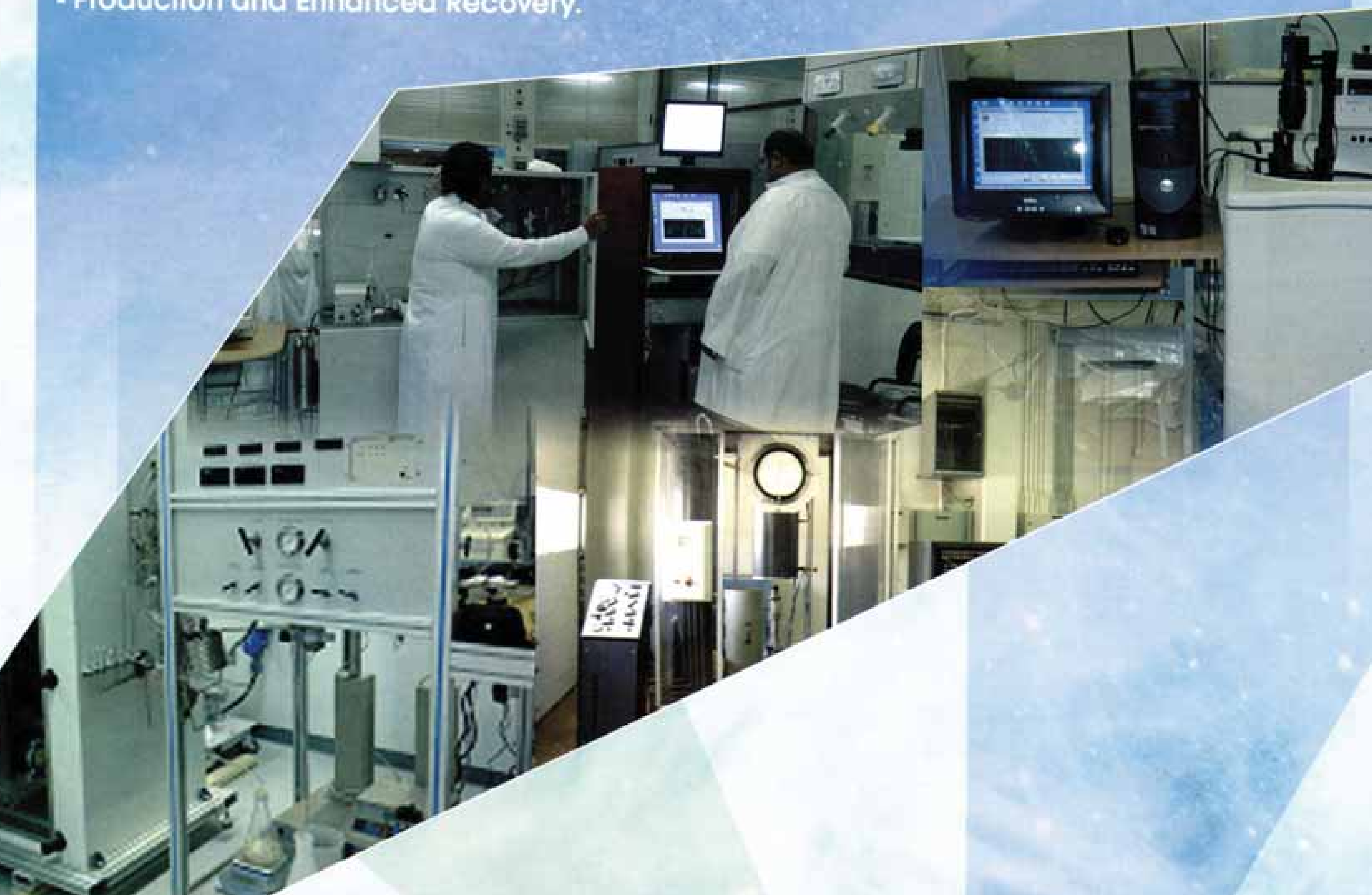
Representative Prediction of Geological Facies

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:

- Reservoir Characterization and Numerical Simulation,
- Drilling Engineering,
- Rock Mechanics,
- Production and Enhanced Recovery.



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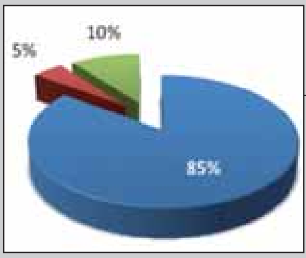

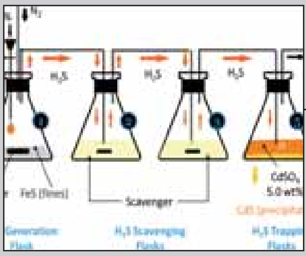

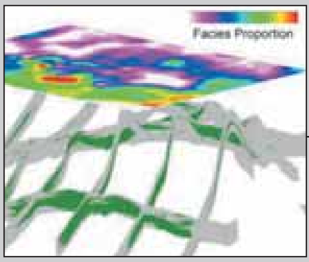

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Ali Habbtar, Chairman
2013 SPE Annual Technical Symposium & Exhibition
Email: ali.habbtar@aramco.com

The submission deadline for abstracts is December 7, 2012, and authors will be notified of proposal acceptance by January 9, 2013.

SUBMIT ABSTRACTS NOW

Employees Earn Top Honors at World Oil Awards

HOUSTON, 21 November 2012

Recognized for their outstanding contributions to upstream innovation, two of six Saudi Aramco award finalists received top honors at the annual 2012 World Oil Awards ceremony on Oct. 18.

Saeed M. Al-Mubarak received the Innovative Thinker award for his contribution in real-time reservoir management over the past 10 years. In the oil and gas industry, he is considered a leading innovator in advanced well completion and "Intelligent Fields," which strategically combine processes, technology and people to achieve the highest performance at the lowest cost. Al-Mubarak oversees one of the world's largest intelligent field projects in Saudi Arabia.

Peter O'Regan, an IT specialist in the e-Map Division, received the New Horizons Idea award for his "game-changing" invention that accurately tracks the physical movement of marine oil spills in real time. His patent-pending system – which uses unique GPS-enabled sensors to track spills as well as advanced GIS mapping to provide live situational awareness to emergency commanders – is being lauded as an industry breakthrough that will ultimately minimize contamination and expedite clean-up activities.

Beginning with a case study in Saudi Arabia's Ghawar oil field – the largest oil field in the world – Al-Mubarak helped to develop the first intelligent field, Haradh Increment III, in South Ghawar.

Al-Mubarak has leveraged knowledge gained from the development of Haradh Increment III and has been generating innovative strategies, operations and data management processes to further new solutions and technologies. By integrating technologies with real-time

> "By integrating technologies with real-time optimization solutions, experts from various disciplines can collaboratively achieve the highest performance of intelligent fields."

optimization solutions, experts from various disciplines can collaboratively achieve the highest performance of intelligent fields.

Al-Mubarak also has patented a specialized valve that prevents cross flow among multiple reservoirs through many segments, or laterals, of a well.

While Al-Mubarak focuses on the anatomy of a reservoir, O'Regan concentrates on boosting Saudi Aramco's emergency response capabilities, both on land and offshore. Saudi Aramco takes special precautions to avoid oil spills and is proactively searching for ways to minimize effects when they occur. Such responses include developing new technology in fluid dynamics that allow scientists to more accurately predict the movement of oil in the ocean and provide additional time for crews to contain a spill.

In collaboration with the IT Future Center and Marine Department, O'Regan developed a system to track the movement of spills 24 hours a day using lightweight, floating sensors that are deployed by helicopter directly into the center and perimeter of an oil slick. The sensors transmit their exact location every 10 minutes and monitor a spill's size, velocity, and potential impact. The sensor data is dynamically merged with live GPS locations of vessels, helicopters, and oil containment booms on rich map displays.

The system will soon be commissioned within Saudi Aramco, and options for commercialization are being explored.

The World Oil Awards event also recognized four Exploration and Petroleum Engineering Center – Advanced Research Center (EXPEC ARC) finalists:

- The Drilling Microchip for the Best Drilling Technology Award category.
- Abdulwahab Alghamdi for the Best Outreach Program.
- Steerable Access Sub for the Best Production Technology Award.
- Hyper-Dimensional Simulator for the Best Visualization & Collaboration Award.

Jazan Project Contracts Signing

JAZAN, 14 November 2012

Under the patronage of HRH Prince Muhammad ibn Nasser ibn Abdulaziz, Amir of the Jazan Area, a ceremony was held November 14, 2012, to sign the construction and procurements contracts of the Jazan Refinery and Terminal.

The ceremony was attended by HE Ali I. Al-Naimi, Minister of Petroleum and Mineral Resources; HRH Prince Faysal T. Abdulaziz, Consultant at the Ministry of Petroleum and Mineral Resources; HE Abdullatif A. Al-Othman, Governor of the General Investment Authority (SAGIA); and Khalid A. Al-Falih, president and CEO, Saudi Aramco.

Located in the coastal part of the City of Bish, at the heart of Jazan Economic City, the Jazan Refinery will be built on an area of approximately 12 square kilometers. Upon completion of the refinery and terminal project in late 2016, the refinery will process 400,000 barrels per day of Arabian Heavy and Arabian Medium crudes to produce gasoline, ultra-low sulfur diesel, benzene and paraxylene.

Khalid G. Al-Buainain, senior vice president, Engineering, Capital & Operations Support, Saudi Aramco, signed the contracts with representatives of eight local and international construction and procurement companies; namely: Al-'Ali Al-Ajmi Group, Petrofac Saudi Arabia Ltd., Hyundai Saudi Arabia Ltd., Hanwa Engineering & Construction Corporation, JGC Corporation, Hitachi Plant Technologies Ltd., SK Engineering & Construction and Technicas Reunidas.

HRH Prince Mohammad N. Abdulaziz, Amir of the Jazan Area, said on this occasion: "Today we witness

> "The Jazan Refinery and Terminal Project will provide more than 1,000 direct jobs in addition to 4,000 indirect jobs."

the realization of the Custodian of the Two Holy Mosques' strategic vision for the Jazan Area through this giant project implemented by Saudi Aramco. We hope this will be only the beginning for further projects in the Jazan Economic City. On my own behalf and on behalf of the people of the Jazan Area, I would like to express the utmost gratitude to the Custodian of the Two Holy Mosques, King Abdullah ibn Abdulaziz, for his attention and follow-up on the development of the Jazan Area, in order for it to take its appropriate economic place locally and regionally. I also commend the efforts the Ministry of Petroleum and Mineral Resources and Saudi Aramco exerted to launch this Project."

HE Ali Al-Naimi said: "The construction of the Jazan Refinery and Terminal comes in realization of the vision of the Custodian of the Two Holy Mosques, of guaranteeing balanced development of the Kingdom's various regions and providing the Jazan, Asir and Najran and other areas with their petroleum products requirements as well as contributing to the development of the Jazan area and its economic city."

HRH Prince Faysal ibn Turki ibn Abdulaziz, Consultant at the Ministry of Petroleum and Mineral Resources, described the project to build the Jazan refinery, terminal and high efficiency power plant as a supporting pillar for industrial activities in the Jazan Area. "This project, in this dear part of our beloved country, will act like a new base for conversion and supporting industries in the Kingdom and an additional source of employment opportunities for the area's inhabitants and will provide the City with a competitive edge through the provision of ample crude oil and energy supplies in this area," he said.

HE Abdullatif HE Abdullatif A. Al-Othman, Governor and Chairman of the Board of Directors, Saudi Arabian General Investment Authority stressed the importance of this critical project and its positive effects on the Jazan Economic City, as the project represents a cornerstone and a real attraction factor to draw more investments to the JEC and the area in general. "Work is underway to develop the required plans to accelerate the JEC's infrastructure construction works in order to attract industrial and service investments, provide appropriate job opportunities for the area's people and form the nucleus of diversified economic activities," he said.

Khalid A. Al-Falih elaborated that the Jazan Refinery and Terminal Project will provide petroleum products to meet the Kingdom's increasing refined product requirements as well as additional volumes to cover demand, particularly in the southern and western parts

> "The project will produce 50 MTA of high-purity silicon, which is used as a feedstock for several industries."

of the Kingdom, while exporting surplus volumes to the global markets.

"The Jazan Refinery and Terminal Project will provide more than 1,000 direct jobs in addition to 4,000 indirect jobs. A multiple-pier marine terminal will be constructed as part of the refinery to supply it with crude oil and support the refined products export operations," Al-Falih said.

He further indicated that, to guarantee the integration of these efforts, Saudi Aramco is currently developing a combined cycle power plant in the area to receive more than 90,000 barrels per day of vacuum residue from the Jazan Refinery and produce approximately 2,400 megawatts of electricity. The power plant will supply the refinery with hydrogen, water and electricity.

The Ministry of Petroleum and Mineral Resources had assigned Saudi Aramco to construct and operate this refinery, which will be wholly-owned by the company and become a part of its refining network, to meet the Kingdom's energy requirements and export surplus products to the world markets.

The Ministry is working to assess an integrated project to produce titanium by utilizing ilmenite, which is locally available in the Qahma region and the coastal area of the southern region. The project includes a plant to produce 500,000 tons per annum (MTA) of titanium ore and 235 MTA of cast iron, another plant to produce 120 MTA of titanium dioxide, and a third plant to produce 20 MTA of titanium powder, in addition to a specialized plant to produce 50 MTA of high-tech final and semi-final titanium products used in desalination applications; oil, gas and chemical industries; the production of aircraft parts; organ transplants and many other industries. The project will also feature a plant to produce white pigments used as additives in the plastics industry, and another to produce zirconium oxy chloride used in manufacturing zirconium compounds and catalysts. The project units will be distributed between JEC and Yanbu' Industrial City to secure the highest possible level of industrial integration between the project units and other existing units. The estimated capital investment for this project is around SAR 5.2 billion. It will generate some 1,600 direct jobs.

The Ministry is also assessing a project to produce silicon in Jazan Economic City to utilize the quartz ore that is locally available in the Asir area. The project will produce 50 MTA of high-purity silicon, which is used as a feedstock for several industries.

The Ministry seeks to integrate this project with a

> … the Ministry is currently considering a project to produce iron sheets, which are used in shipbuilding and in manufacturing the equipment used in the petroleum, petrochemical and desalination industries.

Jazan City silicon polymer production project, which has an estimated initial cost of SAR 500 million and will generate approximately 300 direct jobs.

Both the Economic Cities Authority and the Ministry are also currently evaluating a project for shipbuilding and related activities such as ship repair and maintenance in Jazan City – on the coast of the Red Sea – which is crossed by about 20,000 ships each year.

The project includes dry-docks and ship building and services facilities with an estimated cost of SR 8 billion. The project will generate approximately 2,000 direct jobs.

To enable this industry, the Ministry is currently considering a project to produce iron sheets, which are used in shipbuilding and in manufacturing the equipment used in the petroleum, petrochemical and desalination industries. This project's estimated cost is SAR 4 billion and will generate about 1,200 direct jobs.

Saudi Aramco currently owns and operates four in-Kingdom refineries serving the local market, with a combined refining capacity of 1 million barrels per day. In addition, Saudi Aramco owns 50 percent interests in two other in-Kingdom refineries; namely, Saudi Aramco's joint refinery with ExxonMobil in Yanbu' (SAMREF) and with Shell in Jubail (SASREF). The two refineries have a combined refining capacity of over 700,000 barrels per day. Additionally, Saudi Aramco has an interest in the Petro Rabigh 400,000 barrels per day refinery. This brings the total in-Kingdom refining capacity to more than 2 million barrels per day.

Saudi Aramco also pursues the construction of two 400,000 barrels per day refineries in Yanbu' and Jubail, both designed to process heavier crudes for export to external markets.

Sadara Signs Jubail Land Lease Agreement

JUBAIL, 21 November 2012 – The Sadara Chemical Company and the Royal Commission for Jubail have signed Nov. 13 a land lease agreement for building a world-class integrated chemicals complex in Jubail Industrial City 2.

The signing ceremony took place in Jubail in the presence of HH Prince Saud bin Abdullah bin Thunayan Al-Saud, chairman of the Royal Commission for Jubail and Yanbu', and Saudi Aramco CEO and president Khalid A. Al-Falih, as well as a number of officials from Saudi Aramco and the Royal Commission.

Ziad S. Al-Labban, Sadara CEO, and HE Dr. Mosleh H. Al-Otaibi, CEO of the Jubail Royal Commission, were the signatories to the agreement.

Sadara is a joint venture between Saudi Aramco and The Dow Chemical Co. Once complete, the new joint venture complex will be one of the world's largest integrated chemical facilities, and the largest ever built in a single phase. First production units are expected to come on line in the first half of 2015. All units are expected to be operational in 2016.

Sadara is expected to generate thousands of direct and indirect job opportunities for the Kingdom and deliver annual revenues of about $10 billion within a few years of operation.

After the ceremony, Prince Saud, accompanied by Al-Falih and other Saudi Aramco executives, were taken to Jubail Industrial City 2, where he was shown the work site for the Sadara complex.

The prince was told the complex will cover an area of 6 square kilometers and contain 26 world-scale integrated units that will be built by 15 local and international engineering firms.

He also learned that 7,000 workers are already on the site and that their number is set to peak at 60,000.

Sadara has already begun hiring more than 1,000 Saudis, and about 2,500 employees will be hired over the next three years in preparation for commissioning the facilities.

The manufacturing units at the complex will produce a wide range of performance products such as polyurethanes (isocyanates, polyether polyols), propylene glycol, elastomers, linear low density polyethylene (LLDPE), low density polyethylene (LDPE), glycol ethers and amines.

"Once completed, the 400,000 barrel-per-day full-conversion refinery with integrated petrochemical processing will be one of the most complex refineries in the world."

Sadara will market products within a regional zone consisting of Middle Eastern countries, including the Kingdom. Dow will leverage its global marketing presence and know-how to market and sell on behalf of Sadara to the rest of the world.

Next stop was the Saudi Aramco Total Refining and Petrochemical Company (SATORP) complex, a joint venture between Saudi Aramco and France's Total, which is also located in Jubail Industrial City 2.

Once completed, the 400,000 barrel-per-day full-conversion refinery with integrated petrochemical processing will be one of the most complex refineries in the world. It will be the first producer of paraxylene in the Kingdom.

SATORP has already hired 729 employees and has 350 apprentices in training at Saudi Aramco facilities and refineries.

After completing specialized training at the French Institute of Petroleum and at Total refineries, the first group of young engineers has returned to the SATORP facilities to assist with the start-up. A second group has been recruited and begun similar training.

When completed, the refinery will process Arabian Heavy crude. Its products will fulfill the most stringent specifications to meet rising demand for environmentally friendly fuels.

The full-conversion refinery will maximize production of diesel and jet fuels and will also produce 700,000 metric tons per year (t/y) of paraxylene, 140,000 t/y of benzene and 200,000 t/y of polymer-grade propylene. The refinery will be fully operational by the third quarter of 2013.

Commenting on the tours and the signing, Al-Falih said: "We thank His Highness Prince Saud bin Abdullah bin Thunayan Al-Saud, and all officials of the Royal Commission for their close support for industrial projects and for providing an optimum environment for investment in the industrial cities of Jubail and Yanbu'. We also thank His Highness for his initiative to widen the infrastructure in Jubail Industrial City, and especially in the Jubail Industrial City 2 project, which incorporates Sadara and SATORP.

"This visit is the result of the close cooperation and relationship between the Royal Commission of Jubail and Yanbu' and Saudi Aramco. Both work to support the national economy through mega-projects that will help to provide the Kingdom with thousands of jobs, will support industry and will inevitably enhance the economic position of the Kingdom, regionally and internationally."

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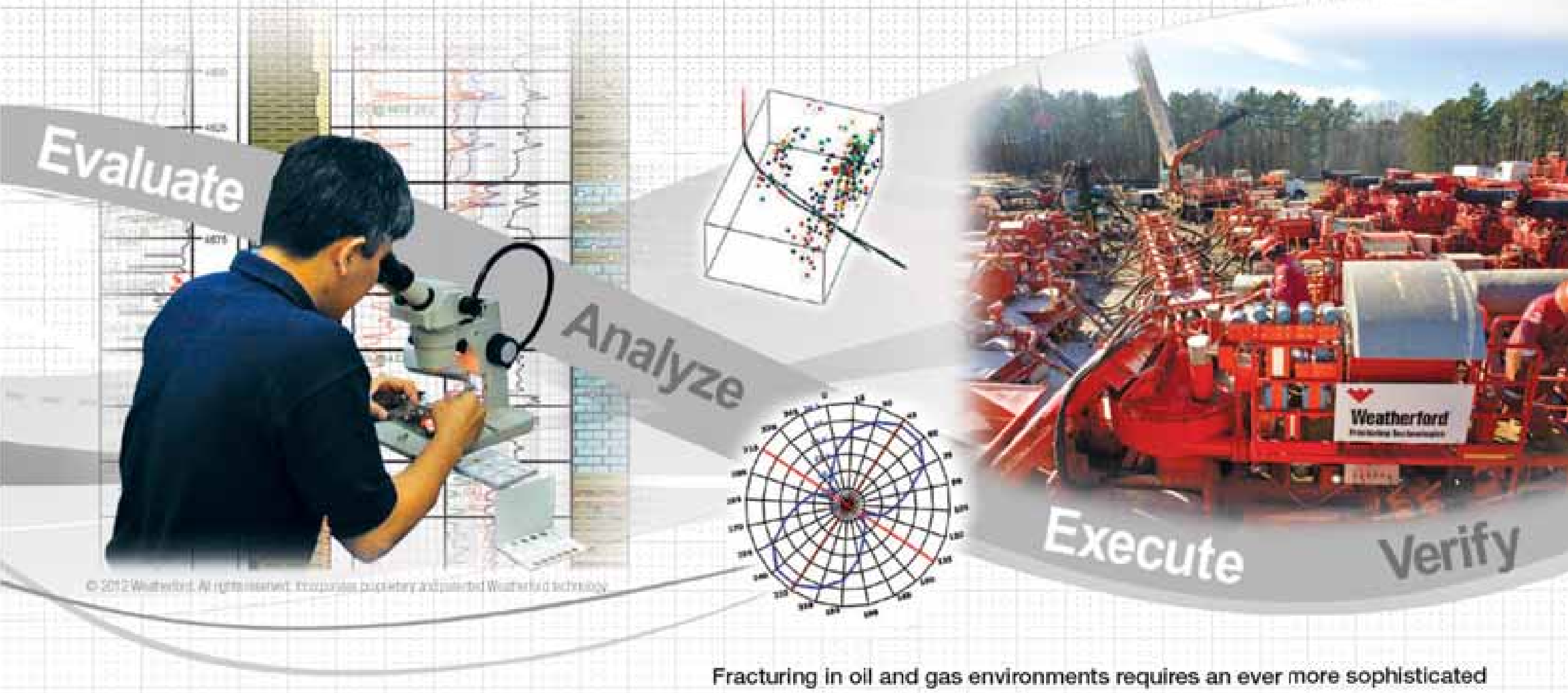

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Cultural Program Opens in al-Hasa

AL-HASA, Saudi Arabia, 5 December 2012 – Through the years, Saudi Aramco has a history of conducting successful programs designed to enlighten and entertain citizens and visitors throughout the Kingdom. From Dhahran to Riyadh and Jiddah to Ras Tanura, the company has extended its special brand of corporate social responsibility with a series of cultural programs that have been embraced by those who visit and take part in them.

This year, the company turned to the famous oasis at al-Hasa as the destination of its popular cultural offering. On Wednesday, Nov. 29, the Cultural Program was launched at King Abdullah Environmental Cultural Park in the presence of al-Hasa Gov. HH Prince Badr Bin Muhammad Bin Jalawi; Saudi Aramco senior vice president of Upstream Amin H. Nasser; and a number of government officials, area businessmen and several members of executive management at Saudi Aramco.

About 5,000 people filled the park for the kickoff of the event, which will run through Dec. 20.

"We in Saudi Aramco are always keen to communicate to our community through programs and events throughout the year, including the Cultural Program that has achieved great success in Dhahran, Riyadh and Jiddah," Nasser said. "Today, it starts in the province of al-Hasa, and we hope its people will take advantage of it and enjoy it."

The al-Hasa Cultural Program contains a variety of activities to suit all tastes and ages and meet the educational and recreational needs of visitors.

Large tents dotted the parks landscape and inside, workshops are offered on topics such as art, calligraphy, folklore and crafts. There are also interactive displays on dinosaurs, mangrove ecosystems, traffic safety and the history of Saudi Aramco.

The al-Hasa Cultural Program will receive visitors in two shifts through Dec. 20. The morning shift is for public and private school children to visit, with the evening sessions open to everyone.

Gas Flare Efforts Recognized

LONDON, United Kingdom, 5 December 2012

Saudi Aramco's gas flare reduction program received special recognition in London on October 24 during a two-day global forum on the topic.

Hosted by the Global Gas Flare Reduction (GGFR) Partnership in association with the European Bank for Reconstruction and Development and the World Bank, the forum brought together the oil majors and national oil companies (NOCs) to examine successes and challenges associated with improving the environment through minimizing the practice of flaring wells around the globe.

The objective was to mark the 10th anniversary of the World Bank-led GGFR Partnership, review past activities, successes and challenges to gas flaring reduction and to determine the way forward for years to come. The World Bank issued a challenge to all oil producers to join global efforts on reducing gas flaring by 2017.

Saudi Aramco was one of the five platinum sponsors, along with BP, Chevron, Statoil and Total. The theme of the forum was "10 Years of GGFR Partnership — Scaling up Flaring Reduction & Gas Utilization for Development."

Gas Operations vice president Ahmad A. Al-Saadi delivered a keynote address on "10 years of GGFR partnerships – The Saudi Aramco Journey."

"In line with the GGFR Partnership, Saudi Aramco and the Saudi Arabian government are cooperating closely to redirect flared associated gas and to optimize this valuable resource's beneficial uses," Al-Saadi told a crowd of more than 200 forum delegates. "But to reach that point, we first had to overcome challenges like virtually eliminating flaring while continuing to meet

> "In line with the GGFR Partnership, Saudi Aramco and the Saudi Arabian government are cooperating closely to redirect flared associated gas and to optimize this valuable resource's beneficial uses"

the global demand for crude oil. I believe our approach is worth sharing, as a strategy for organizations addressing similar concerns."

Al-Saadi later took part in a panel debate along with senior representatives from the World Bank, Chevron, Statoil and the Minister of Hydrocarbons from the Republic of Congo.

At an awards banquet, Saudi Aramco garnered a special award for "Excellence in Gas Flare Reduction Program". Al-Saadi accepted the award on behalf of the company and recognized all those parties who contributed to the program and brought it to its successful fruition.

"Saudi Aramco has been a pioneer in terms of reducing flaring and developing gas utilization projects, and thanks to their visionary policies, they have not only successfully avoided millions of tons of CO_2 emissions, but they have also created thousands of jobs, by developing a huge gas related industry," GGFR manager Bent Svensson said of the company. "This is a model for other countries in their approach to gas flaring reduction."

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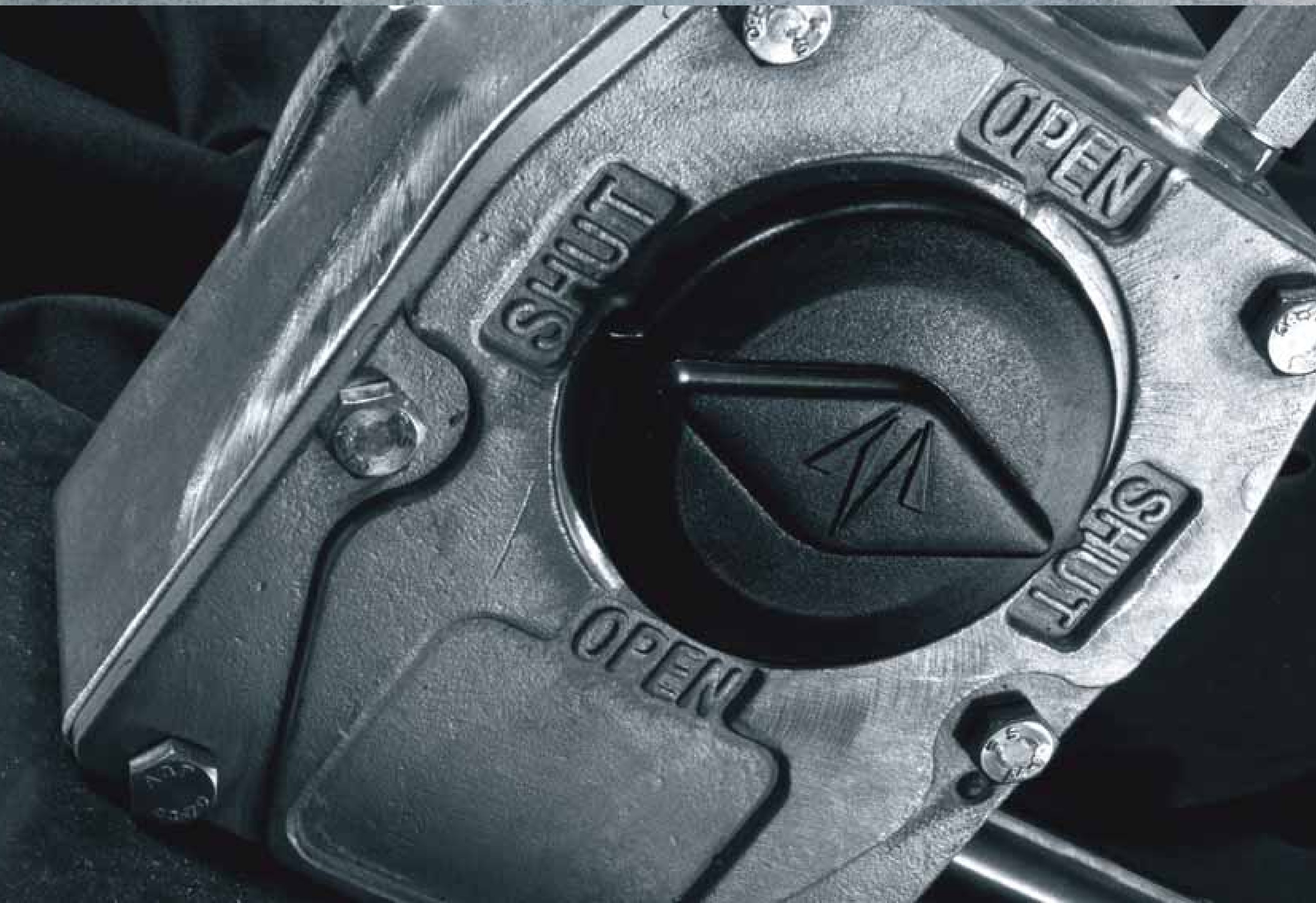

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Remarks at Jazan Refinery Signing Ceremony

By Khalid A. Al-Falih, President and CEO, Saudi Aramco.

JAZAN, Saudi Arabia, 14 November 2012

"Your Royal Highness Prince Mohammad ibn Nasser ibn Abdul Aziz Al-Saud, Amir of the Jazan Area,

Your Highnesses, your reverences, your excellencies, distinguished guests, good morning.

Let me begin by thanking you all for joining us today in celebrating this new national project in the Jazan Area, a promising part of our beloved Kingdom. Today, we launch the giant Jazan Refinery and Terminal Project by signing its main engineering, procurement and construction contracts, in realization of the vision of this country's leader, the Custodian of the Two Holy Mosques, who, a few years ago, launched an initiative to achieve balanced development, boost economic growth in all areas of the Kingdom and generate more employment opportunities for its citizens.

This iniative included this pioneering project in Jazan, which King Abdulaziz enthusiastically and continuously followed up on in person, until its feasibility and engineering studies were completed, and the phase of constructing it and bringing about its expected prosperous future, which is about to take place today.

We also received continuous support from His Royal Highness Prince Mohammad ibn Nasser ibn Abdul Aziz, Amir of the Jazan Area, who encouraged the Project as a major and significant part of the array of industrial facilities that supplement the giant developmental feats launched in this area.

This Project also enjoyed the continuous care and support of His Excellency the Minister of Petroleum and Mineral Resources, Ali ibn Ibrahim Al-Naimi, and the direct oversight of His Royal Highness Prince Faysal ibn Turki ibn Abdul Aziz. Such oversight and support played the most important role in reaching the current phase of the Project with optimal planning and implementation.

Respected guests, the project we are launching today is distinguished in all its aspects. During the past 20 years, only three refineries of this size and capacity have been constructed. Once completed by the end of 2016, the Project will be capable of processing 400 thousand barrels per day (MBD) of heavy and medium Arabian crudes. Furthermore, the whole project is, naturally, backed by Saudi Aramco's commitment to operational excellence, safety, and environmental stewardship in one of the most beautiful parts of the Kingdom.

The Terminal, which is part of the Project, will accommodate Very Large Crude Carriers (VLCCs).

The Project also features a 2400-MW high-efficiency combined cycle power plant to fulfill the electricity requirements of the Refinery as well as a large part of the electricity needs of the west coast.

Based on the project size I referenced earlier, the Project is expected to generate 1,000 direct jobs and 4,000 indirect jobs. In addition, Jazan area will become a major destination for domestic investment. The Refinery will play the main role in providing the Western and Southern Regions with their requirements for refined

> "... the whole project is, naturally, backed by Saudi Aramco's commitment to operational excellence, safety, and environmental stewardship in one of the most beautiful parts of the Kingdom."

products, and the excess volumes will be exported. The Project will raise gasoline production by 80 MBD and diesel production by 250 MBD, and will produce approximately 1 million tons per annum (MTA) of benzene and paraxylene petrochemical products.

Jazan Refinery and Terminal Project means so much more for the Jazan Region. This Project will form the backbone of the Jazan Economic City, playing a key role in its development and providing the city with a competitive advantage – in the availability of feedstock for downstream industries as well as energy and fuel – thus creating an industrial city capable of attracting investors.

In this manner, the Project will realize more developmental value for the Kingdom and serve our national objective of establishing an integrated knowledge economy.

I would like to address our partners – the contractors – with whom we sign the contracts today, congratulating them on winning the engineering, procurement and construction contracts, and assuring them that they were selected through accurate procedures, to guarantee that they enjoy the high level of professionalism that qualifies them for a giant project of this type. This professionalism is why we expect from them disciplined and organized work per the schedule established for completing the Project. I have no doubt that they all look forward to sharing with us the pride we will all be taking in realizing and completing this Project, when we meet to bring it on stream in the service of our national economy.

Before I conclude my speech, I would like to remind our partners that we all have one common basic goal; the creation of employment opportunities for thousands of Saudi youths during the various phases of the Project, through the combined efforts of Saudi Aramco, the Technical and Vocational Training Corporation and the contractors themselves; to provide training for those young people.

Finally, allow me, Your Royal Highness, to express my utmost gratitude for your responsive and direct support for this Project. I would also like to thank the Ministry of Petroleum and Mineral Resources for trusting in us and giving us the opportunity to plan, construct and operate this Project.

I also value the efforts of the General Investment Authority and the Economic Cities Authority, represented here today by His Excellency Abdullatif ibn Ahmad Al-Othman, in facilitating the operations of this Project.

Once more, I would like to thank you all for attendance and support, and hope we will meet again in other similar occasions.

Powering Possibilities: Introducing Aramco Asia Korea

SEOUL, Republic of Korea, 14 November 2012

“Your Excellencies, ladies and gentlemen:

Saudi Aramco is honored by your presence as we inaugurate a new company, Aramco Asia Korea. The office is in the heart of the business and governmental districts, near the Blue House and the headquarters of Korea’s leading enterprises. We are building a team of energetic and experienced professionals, representing the best of Saudi Aramco. Our new enterprise in Korea represents exciting developments.

Aramco Asia Korea reports directly to Saudi Aramco headquarters in Dhahran. It supports the full spectrum of Saudi Aramco’s interests in Korea. These include not only marketing, but also procurement and liaison with engineering and project management contractors, and interaction with Korea’s sophisticated research and development community.

We are thrilled to have a vital economic stake in a nation enjoying a great renaissance. In every corner of the world today, people associate Korea with quality, innovation, and competitive pricing. From automobiles to shipbuilding to complex engineering projects to high-tech electronics, “Made in Korea” is an emblem to be trusted.

For quite some time, Korean exporting success has been the envy of many other countries. Now the export triumphs also include pop culture. Saudi families increasingly are traveling to Korea as tourists, and young people in my country are in love with Korean movies and music. Even in the deepest deserts of Saudi Arabia, there is no escaping the popularity of “Gangnam Style.”

My friends, innovation requires keen perception and discipline. These are deeply ingrained in the Korean mindset.

Let me mention a brilliant example of how that mindset has impressed us at Saudi Aramco.

At the beginning of our long relationship with this country, the Korean government agency concerned with the oil business was called the Ministry of Energy & Resources. Over the past generation, this organization merged with the Ministry of Commerce, Industry & Energy. More recently, the combined organization was given a new name. Today it is called the Ministry of Knowledge Economy.

This name, my friends, is utterly ingenious. It speaks a profound truth – with lessons for every company and every individual in the energy business.

Yes, as the Korean people understand perhaps better than anyone else on the planet, knowledge is energy. Knowledge is wealth. Knowledge – the product of careful perception and discipline – is innovation. Human creativity is both a natural resource and the wellspring of technological miracles.

For this reason, Korea is widely recognized as the

> “Korean engineering and construction firms now are engaged in contracts valued at more than $14 billion in major Saudi Aramco projects and joint ventures in Saudi Arabia.”

greatest entrepreneurial society in modern history. And fortunately, the “Korean Miracle”, which is also called “Miracle on the Han River”, is not merely a happy fact of the recent past.

It is a booming force of global progress for today and for the future. That is why, ladies and gentlemen, Saudi Aramco is elevating and expanding its presence in Korea.

In a few moments you will hear from the new managing director of Aramco Asia Korea, Mr. Mohammed Al-Madi. He earned his bachelor’s in industrial management and his master of business administration from King Fahad University of Petroleum and Minerals in Saudi Arabia.

He is conversant in three languages in addition to his native Arabic. He has performed superbly in roles including capital budgeting, international crude oil sales and marketing, and, most recently, as regional vice president of Saudi Petroleum Limited in Beijing. He clearly is a man committed to lifelong learning. Only last year, he completed the requirements for a PhD degree in petroleum engineering from China’s University of Petroleum in Beijing.

Mohammed and his team will build Aramco Asia Korea on the foundation of a long and deeply rewarding relationship between Saudi Aramco and our customers, suppliers, technology partners and other stakeholders in this country.

For many years we have been the largest supplier of oil to power Korea’s thriving economy, with several major refineries as our valued customers. We have a strong partnership in the refining business in Korea, as we recently marked the 20th anniversary of our S-Oil joint venture.

And over the years, too, Korea’s skilled and conscientious manpower and its superb, cutting-edge technologies have added tremendous value to many of Saudi Aramco’s largest and most critical projects. Saudi Arabia owes many of its most remarkable and enduring infrastructure projects to the genius and work ethic of Koreans.

That tradition of excellence continues and grows stronger with each passing year. Korean Foreign Direct Investment in Saudi Arabia grew from 45 to 99 projects between 2006 and 2010, with the value of direct investments increasing by more than 400 percent over the same period. Korea also is now Saudi Arabia’s fourth-largest trading partner. Korean engineering and construction firms now are engaged in contracts valued at more than $14 billion in major Saudi Aramco projects and joint ventures in Saudi Arabia.

> "As Saudi Arabia's economy continues to develop, we can envision a day when Korean firms also become partners with Saudi Aramco in joint ventures within the Kingdom"

Additionally, Saudi Aramco recently signed contracts with three Korean firms for engineering and construction of a new 400,000 barrel-per-day domestic refinery in Jazan in the southwest of Saudi Arabia. Korean financial institutions also are vital partners in Saudi Arabia. They currently have committed more than $3 billion in project finance for joint ventures in Saudi Arabia. As Saudi Arabia's economy continues to develop, we can envision a day when Korean firms also become partners with Saudi Aramco in joint ventures within the Kingdom.

Saudi Aramco sends some of our most promising students here to learn in Korea's world-class universities and research institutes. We are proud to have a number of them here tonight.

The theme of tonight's dinner is "Powering Possibilities". This is a phrase Saudi Aramco uses globally to express our capabilities and aspirations. And certainly nothing could be more fitting than this to describe the thrilling opportunities we see ahead in our relationship with Korea.

Korea is a model of inspiration for goals of social and economic progress to which the young, fast-growing population of Saudi Arabia aspires.

Six decades ago, Korea defied the pessimism of conventional thinking. The pessimists looked at Korea and saw a population lacking in natural resources and infrastructure. The short-sighted saw poverty and weakness. But the visionaries who shaped today's Korea saw power in possibilities – in human potential. They believed in the vast capacity of the Korean people's minds and hearts. I sincerely admire the success of the Korean economy and also respect the Korean people, who made transformation possible only through their hard work, diligence, and confidence.

Fifteen years ago, the Korean people again showed a shining example to the world. From the depths of the IMF crisis, Korea adopted a disciplined and effective plan for recovery. As a result, today Korea's per capita GDP has tripled since the crisis.

The Korean spirit, and the enduring friendship and shared sense of enterprise between Saudi Aramco and our Korean partners, give us much to celebrate tonight.

Ladies and gentlemen, thank you again for your presence this evening. Thank you for sharing our belief in the innovative possibilities and the productive power of Aramco Asia Korea."

Advanced Utilization of Downhole Sensors for Water-cut and Flow Rate Allocation

By Meshal A. Al-Amri, SPE, Faisal T. Al-Khelaiwi, SPE, and Mohammad S. Al-Kadem, SPE, Saudi Aramco.

This paper was prepared for presentation at the Abu Dhabi International Petroleum Exhibition & Conference held in Abu Dhabi, UAE, 11–14 November 2012.

Abstract

Downhole pressure and temperature sensors have been installed either separately as stand-alone sensors hanged on the production tubing of a well or jointly with Electric Submersible Pumps (ESPs) or Intelligent Well Completions (IWC). However, their utilization thus far has been limited to static/flowing bottom-hole pressures measurement for buildup/drawdown pressure tests analysis or ESP/intelligent well performance monitoring.

Eighty-eight (88) wells located offshore Saudi Arabia have been equipped with ESPs combined with downhole pressure and temperature sensors installed at the intake and discharge of the pumps. Each well was equipped with a surface coriolis meter to measure the total liquid flow rate and water-cut assuming that the well's production will be maintained above the bubble point pressure. However, the coriolis meters' readings have become erroneous ever since the wells' flowing wellhead pressure declined to and below the saturation pressure due to the flow of liberated gas through the meters. In order to compensate for the meters' measurement deviation, wellhead samples had to be collected and analyzed to determine the wells water-cuts where the total flow measurement was still acceptable. Alternatively, other means of multiphase flow rate measurements were used. This has proven to be costly and time consuming.

This paper proposes a technique which uses real-time data transmitted from existing surface and subsurface sensors to calculate the water-cut and flow rate of each well and avoid the risky and costly field trips for wellhead sample collection and analysis. In addition, the paper describes an innovative technique to estimate the error in the measured density and calculated water-cut based on the bubble point pressure which accurately determines the application envelope of this method. The paper provides examples to illustrate the validity of the proposed technique in comparison with measured and sampled water-cuts which were collected above and below the bubble point pressure. Furthermore, the paper sheds light on the main issues impacting the method's reliability.

Introduction

Eighty eight wells in an offshore Saudi Arabian field are equipped with Electric Submersible Pumps (ESP) to lift the produced fluid from the producing reservoir to the onshore processing facility and maintain the field's target production rate. This required very close monitoring of the ESPs performance to optimize the pumps lifting operation and maximize the wells deliverability. The field was also designed to produce above the bubble point pressure at surface and hence each well was equipped with a coriolis flow meter along with pressure and temperature transmitters at various locations along its surface flowlines to provide continuous-real time data of the wells' performance. Such data when combined with the ESPs operating parameters such as frequency, voltage, intake and discharge pressures provided both production and reservoir engineers with great control of the reservoir and field overall performance.

However, the decline in the reservoir pressure combined with the increase in the field production to compensate for the increase in the produced water led to the decline in the surface network pressure to (or below) the bubble point pressure. Subsequently, the decline in wellhead pressure enabled the solution gas to liberate and flow freely in the production tubing and flow lines of each well causing errors in the wells' flow rate measurements. To overcome these measurement errors, wellhead samples were collected manually by field personnel through boat visits to each platform. The samples were then analyzed for water cut in the laboratory. This technique was applied where the coriolis total liquid measurement was still acceptable. In other cases, a portable multiphase testing separator was used to acquire the well production rates. Both of these solutions proved to be costly and time consuming.

The following sections will discuss the causes of the coriolis meter measurement errors and describe the solution used to mitigate such errors taking advantage of the ESP and wellhead sensors.

Factors Impacting Coriolis Water-cut Calculation

The objective of a coriolis meter is to provide the mass flow rate and density of the flowing fluid which in turn can be used to calculate the volumetric flow rate and water or gas cut1. In the offshore field described in this paper, the coriolis meters were used to calculate the volumetric liquid flow rate and water cut of each well. Although the volumetric flow rate can be attained by simple division of the mass flow rate over the density measured by the meter, calculating the water cut depends on several factors including:

Water density at operating conditions should be greater than both oil and oil/water mixture densities. Changes in the water density can be caused by several factors including temperature and pressure changes. Hence, such factors have to be taken into account when calculating the water density.

API gravity at the operating conditions can be used for the calculation of oil and gas density but each well has to have its own API value for accurate measures. As the API gravity increases, the calculated oil density will decrease and hence the water cut increases.

Operating surface pressure below the bubble point

Operation Pressure (psig)	Gas Volume Fraction at 10% water cut (%)	Gas Volume Fraction at 20% water cut (%)
300	0.0	0.0
280	6.1	5.5
250	16.9	14.5
225	25.7	23.6
200	34.3	31.9

Table 1: GVF changes with operating pressure and water cut changes.

pressure will generate an entrained gas. This gas will reduce the mixture density and hence it will decrease the water cut reported by the coriolis meter.

Liquid density of the flowing fluid is questionable in the existence of entrained gas. In homogeneous oil/water mixture flow, the liquid density values should be between the oil and water densities and hence the water cut will always be directly proportional to the liquid density.

PVT Data and Bubble Point Pressure Analysis

The Pressure Volume Temperature (PVT) data of the producing reservoir was used to determine the Gas Volume Fraction (GVF) levels at various operating pressures and water cut values. Table 1 shows the results of the GVF analysis. It is clear that doubling the water cut has very little effect on the GVF of the surface stream; and therefore any reduction in the network pressure below the bubble point pressure results in free gas flow in the system. Since the mixture density value generated by the coriolis meter is affected by the gas in the flow stream, incorrect oil and water volumetric flow rates will be generated.

Problem Investigation

After thorough assessment of the erroneous water cut values, the following was discovered:

• 5% of the wells require Supervisory Control and Data Acquisition (SCADA) and Process Information (PI) reconfigurations since the assessment revealed wrong input/output data mapping, point description discrepancies, and missing important information on the SCADA and PI graphics.

• 10% of the wellhead pressure and temperature transmitters are defective and require replacement. It is important to note that wellhead pressures and temperatures are used to calculate the oil and water densities at operating conditions. Defective transmitters will produce erroneous values which in turn affect the chain of calculations, especially the water cut values.

• Water cut calculations, which are based on the mixture density values generated by the coriolis meter, will always produce incorrect results.

Fig. 1 shows a breakdown of these issues

Proposed Solution

The previously applied solution to the erroneous water cut was manual sampling; where Field services personnel conduct monthly trips to the offshore platforms to collect samples and deliver these to the laboratory for Basic Sediment and Water (BS&W) analysis. Thereafter, the oil flow rate is calculated based

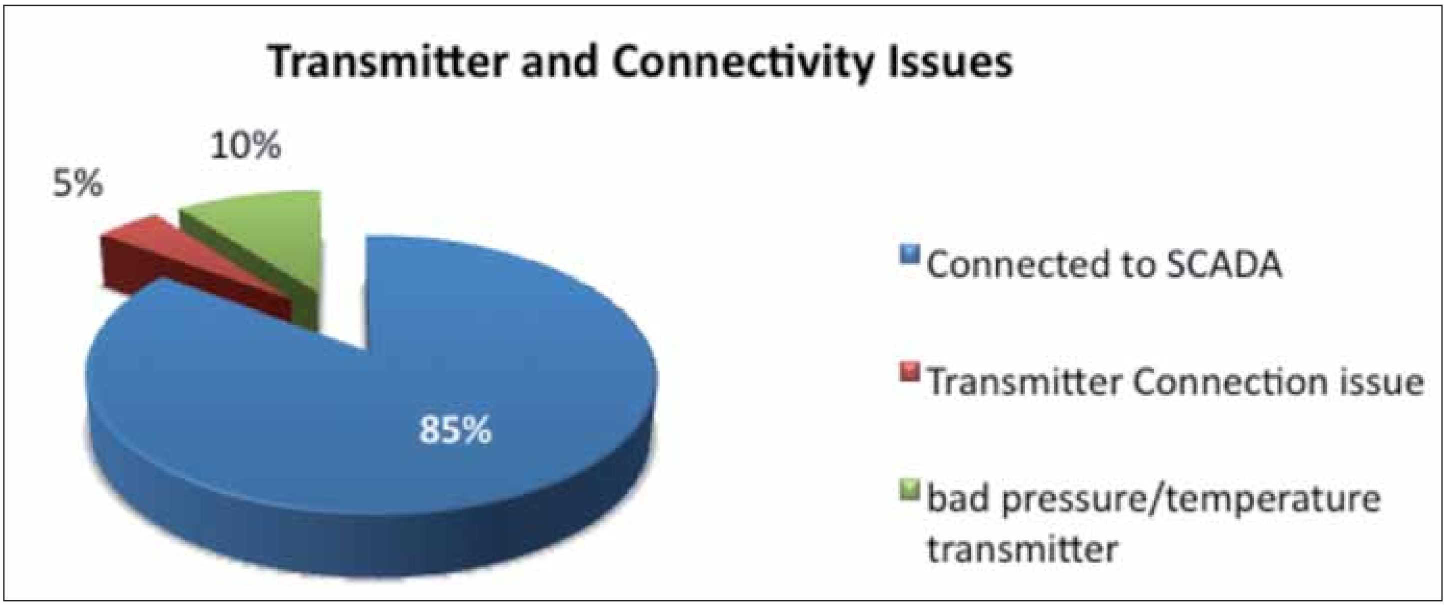

Fig. 1: Transmitters SCADA Connectivity Status.

on the lab reported water cut and coriolis meter flow rate provided that the meter is providing reasonably accurate flow rate. Alternatively, a portable multiphase separator was used to measure the well flow rates. Both solutions are costly and time consuming.

The proposed solution consists of two parts: water cut and volumetric flow rate estimation. The water cut estimation is based on the produced fluid gradient calculation in real time using the ESP and wellhead sensors data3. Subsequently, the well's flow rate estimation is performed using commercially available software which uses the pump curves with the estimated water cut as an input parameter. These two parts of the proposed method are described below:

Water cut estimation uses the Poettmann and Carpenter model, which was coded by Guo and Ghalambor4, to estimate the fluid density using the pressure difference between the ESP discharge and wellhead sensors. Then, the mixture density is used with the oil and water densities at the surface operating conditions to calculate the water cut. The following three steps should be performed to apply this solution:

1. The oil and water density correlations2 listed below, Eq. 1 and Eq. 2, were used to calculate the oil and water density at the operating condition.

$$\rho_o = A - [0.0004\times(1000 - P)] + [0.0255\times(200 - T)] \quad \text{Eq.1}$$

$$\rho_w = \{[-0.00006\times(T)^2] - [0.0 \quad \text{Eq. 2}$$

Where: ρ_o is the oil density in Ibs/ft^3, ρ_w is the water density in Ibs/ft^3, A is the oil density at standard conditions in Ibs/ft^3, B is the water density at standard conditions in Ibs/ft^3, T is the Temperature in degrees Fahrenheit and P is the Pressure in psig.

For general application, such equations should be generated from the PVT data of the field where this technique will be applied.

2. ESP discharge pressure, wellhead pressure and wellhead temperature should be used to calculate the mixture density using Eq. 3:

$$\bar{\rho}_{mix} + \frac{\bar{k}}{\bar{\rho}_{mix}} = 144\left[\frac{P_{DIS} - P_{FWH}}{D_{DIS}}\right] \quad \text{Eq. 3}$$

The positive root of the quadratic equation is used to solve for the average mixture density as follows:

$$\bar{\rho}_{mix} = \frac{144\left(\frac{P_{DIS} - P_{FWH}}{D_{DIS}}\right) + \sqrt{\left[144\left(\frac{P_{DIS} - P_{FWH}}{D_{DIS}}\right)\right]^2 - 4\bar{k}}}{2} \quad \text{Eq. 4}$$

Where: ρ_{mix} is the average fluid mixture density in Ibs/ft^3, P_{DIS} is the ESP discharge pressure in psig, D_{DIS} is the ESP discharge pressure depth in ft, and P_{FWH} is the flowing wellhead pressure in psig. k is defined below:

$$\bar{k} = \left[\frac{f_{2F}\times q_o^2\times M^2}{7.4137\times10^{10}D^5}\right] \quad \text{Eq. 5}$$

Where: q_o is the oil production rate in stb/day, M is the total mass associated with 1 stb of oil, D is the tubing inner diameter in ft, and f_{2F} is the Fanning friction factor of two phase flow as indicated below:

$$f_{2F} = 10^{1.444 - 2.5\times log\left[\frac{1.4737\times10^{-5}\times q_o\times M}{D}\right]} \quad \text{Eq. 6}$$

In this calculation, the oil mass and volumetric flow rate were replaced by the liquid mass and volumetric flow rates, which were measured by the coriolis flow meter. These were used as initial estimates for the calculation of *k* and *f_{2F}*.

The water cut should be calculated using Eq. 7.

$$W/C = \left[\frac{\bar{\rho}_{mix} - \rho_o}{\rho_w - \rho_o}\right]\times100 \quad \text{Eq. 7}$$

Where: W/C is Water Cut in %.

Flow rate estimation uses the well calibrated model of commercially available software such as GAP™/PROSPER™ 5 or PIPESIM™. The software uses the estimated water cut described above as an input parameter along with the other fluid parameters such as the solution gas and oil gravity in addition to the ESP design and operating parameters such as ESP depth, outer diameter, number of stages, motor features, cable features, operating frequency and ESP voltage. The ESP wear effect can also be accounted for in the software. These parameters are used to run an iterative algorithm that will provide an estimate of the well production rate.

The well models used in this field were built in GAP™/PROSPER™ and water cut estimation was programmed in Visual Basic Application (VBA) language to automate the water cut calculation and enable real time estimation of the well's three phase flow rates.

Error Estimation

The fluid mixture density estimated using Eq. 4 will

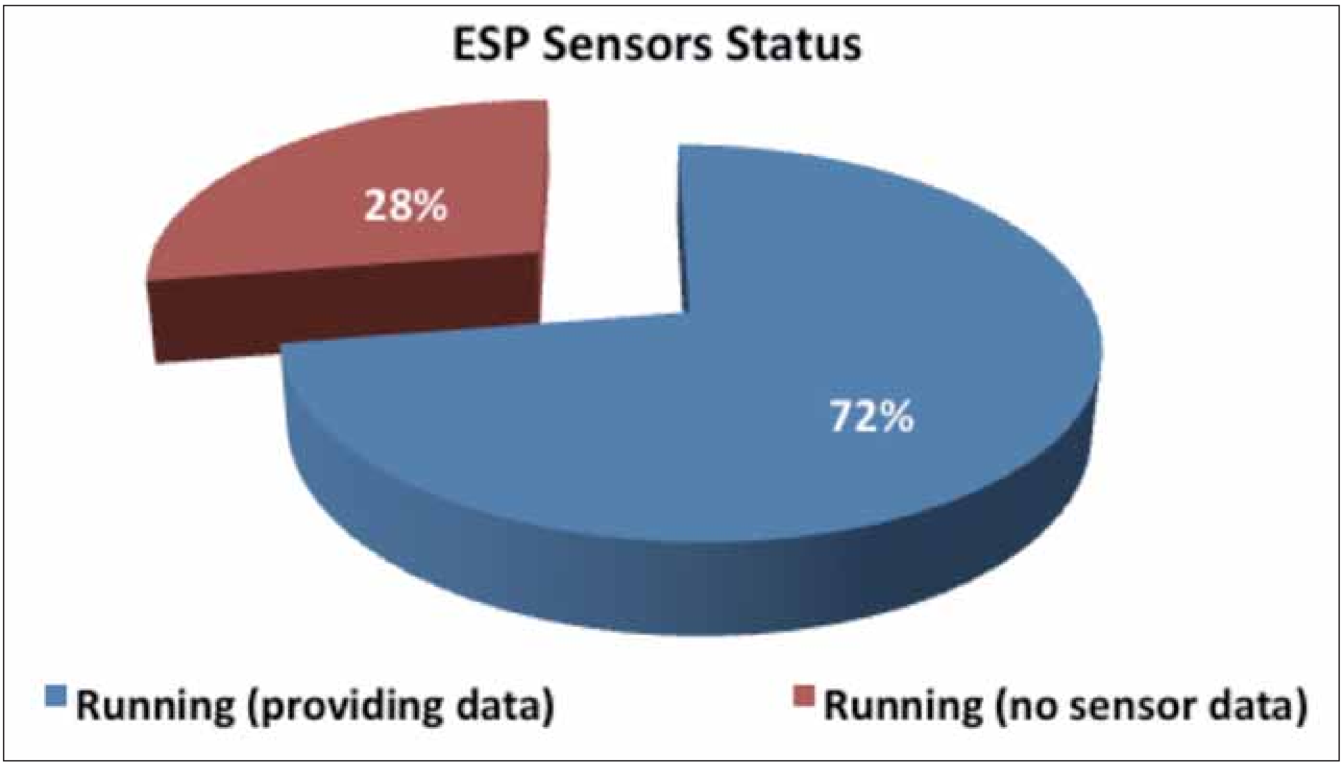

Fig. 2: ESPs sensors status

start to deviate from the actual liquid density at the bubble point pressure since gas will come out of solution and lighten the fluid gradient. This deviation between the two values can be quantified using tubing flow performance correlations in commercially available software in the following process:

1. Sensitivities were curried out using a segmented well model in the PROSPER™ production software to quantify the impact of changes in the well flowing parameters on the fluid mixture density. These include the flowing wellhead pressure, the water cut, the flow rate and the well deviation. The results of these sensitivities were used to cross check the mixture density calculated using Eq. 4.

2. The percentage error between the mixture density estimated using Eq. 4 and the liquid density calculated using the software was calculated using Eq. 8. If the percentage error is low, then the water cut estimated using Eq. 7 was considered good for use in the flow rate estimation. In our case the percentage error was limited to 10%.

$$Error = \left[\frac{\bar{\rho}_{mix} - \rho_{liq}}{\bar{\rho}_{mix}}\right] \times 100 \qquad \text{Eq. 8}$$

Where: Error is error between the mixture and liquid densities in % and ρ_{liq} *is the liquid density in Ibs/ft*^{3}.

In this field, the tubing length has been divided into 60 segments. The liquid density was calculated using PROSPER™ to identify the depth where the bubble point pressure is reached. The objective is to estimate the error from the calculated mixture density based on the assumption that the free gas will not affect the gradient calculation since the entrained gas is just below the surface. Table 2 illustrates that the mixture density calculated by PROSPER™ is significantly affected by the gas. However, the mixture density estimated using Eq. 4 is valid and can be used to estimate the well water cut and flow rate since the error between this estimated mixture density and PROSPER™ liquid density is 0.14%. This confirms the reliability of the proposed method and provides an envelope for its application. It should also be noted that an increase in the depth of the bubble point pressure will increase the percentage error between the estimated mixture density and the software liquid density.

Limitation of the Proposed Solution

The basic intent of the proposed method is to reduce sampling requirements and to provide continuous real-time estimation of the well water cut and flow rate. Subsequently, the proposed method depends on the operability and accuracy of the wellhead and ESPs sensors as well as the accuracy of the oil and water density correlations generated from the PVT

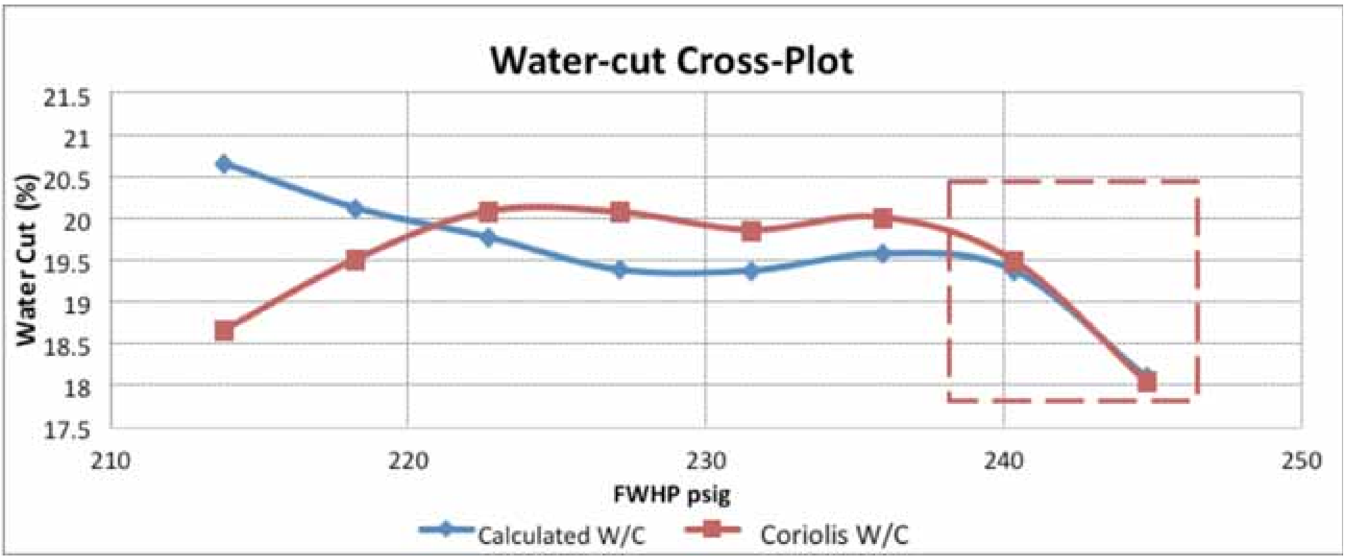

Fig. 3: Water-cut cross-plot for a test with duration of 4 hours.

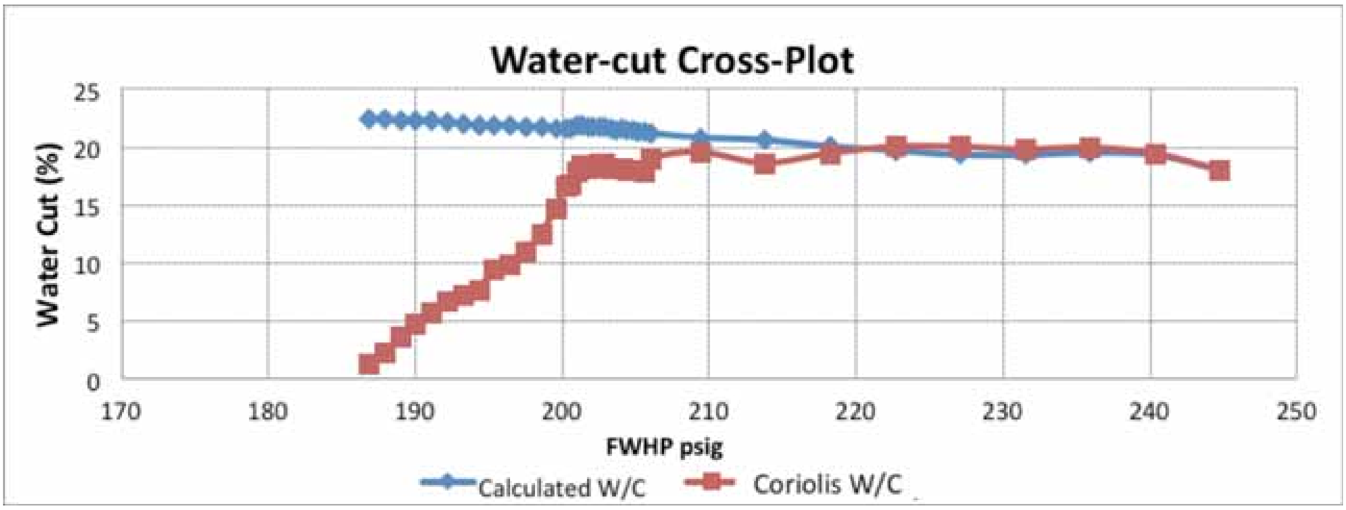

Fig. 4: Water-cut cross-plot for a test with a duration of 6 hours

parameters of the produced reservoir. In the field where this technique was applied, the sensors' connectivity to the SCADA system was one of the main issues that were encountered as indicated in Fig. 1. Also in this field, 28% of the operating ESPs have one grounded phase resulting in the loss of their sensors' signal as depicted in Fig. 2; limiting the application of this technique to 70% of the wells with healthy and communicating ESP and wellhead sensors.

In addition, this methodology should not be applied on wells with free gas production from the reservoir gas cap or from producing the reservoir below the bubble point at the sand face (i.e. prior to the ESP discharge). This because the gas influx below the ESP discharge pressure sensor will lighten the liquid/gas mixture density. Such density values will not be useful in the proposed calculation.

A case study is summarized below to show the impact of the pressure drop and subsequent gas liberation on the coriolis meter measurement. In addition, the case study will illustrate the reliability and applicability of the proposed water cut and flow rate estimation method.

Well-X1 Case Study:

This study has been conducted on Well-X1, which is located offshore and completed with an ESP, at a time when a high production network pressure was imposed on all the producing wells in the field causing the wellhead pressure of all wells to reach the bubble point pressure. The high wellhead pressure was caused by partial closure of the plant inlet control valve. After opening the valve, the network and wellheads pressure started to decline to the normal production pressure. During the pressure increase to the bubble point, the coriolis meter started reporting more accurate density values and hence positive water cut values. Therefore, the coriolis meter reading was used to verify the reliability and accuracy of the calculated water cut using the proposed technique. In addition, water cut samples that were collected at the same period were compared to both the coriolis meter and calculated water cut values.

As described above, four important parameters have to be identified to perform the water cut estimation: the ESP discharge pressure, the flowing wellhead pressure and temperature, and the ESP discharge pressure sensor depth.

Fig. 3 shows the calculated water cut values using the proposed method which matches the coriolis meter values at high pressure then starts to increase at lower pressure indicating an increase in the water cut as the well production rate increases with the reduction in wellhead and network pressures. This figure also shows the impact of the free gas liberation and flow on the coriolis meter values which starts to decline as the wellhead and network pressure declines. Moreover, the water cut value of the wellhead sample was 17%.

Fig. 4 shows that the proposed water cut calculation method continues to provide reliable data when compared with the coriolis meter values which continue to impractically decrease as the pressure declines away from the bubble point.

GAP™/PROSPER™ was used to confirm the reliability of the estimated water cut and calculate the well flow rate. The ESP design and operating parameters listed in Table 3 were used in the well model. The estimated mixture density was within 0.14% of the liquid density reported by the software at 20% water cut. The well produced a liquid rate of 6151 stb/day and oil rate of 4921 stb/day at flowing wellhead pressure of 230 psig.

Conclusion

Coriolis flow meters were installed on 88 ESP lifted wells to monitor their flow rate in real time. However, the low production network pressure caused the wells to produce below their bubble point pressure. This introduced free gas into the system impacting the density and water cut measurement of the coriolis meters.

The proposed solution in this paper used the existing ESP and wellhead sensors to estimate the water cut and flow rates of the producing wells with operable and communicating downhole and surface sensors. This method proved to be reliable and cost effective when compared to manual sampling or utilization of portable separator. The applicability of this method to the well can also be determined through the use of commercially available software.

This method is not limited to ESP wells since it can also be applied to wells with single downhole sensor, permanent downhole monitoring system.

Acknowledgement

The authors would like to extend their appreciation to the management of Saudi Aramco, Northern Area Production Engineering and Well Services Department for their permission to publish this paper. The authors

Prosper Mixture Density	Prosper liquid Density	Cal. Mixture Density	Error of cal. Mixture Density from Prosper Mixture Density	Error of cal. Mixture Density from Prosper Liquid Density
(lb/ft3)	(lb/ft3)	(lb/ft3)	%	%
25.39	54.57	54.49	53.40	0.14
31.57	54.18	54.49	42.06	0.57
38.15	53.78	54.49	29.99	1.31
45.49	53.35	54.49	16.52	2.08
52.93	52.93	54.49	2.86	2.86
52.86	52.86	54.49	2.99	2.99
52.79	52.79	54.49	3.12	3.12
52.72	52.72	54.49	3.25	3.25
52.65	52.65	54.49	3.37	3.37
52.61	52.61	54.49	3.45	3.45
52.59	52.59	54.49	3.49	3.49
52.54	52.54	54.49	3.57	3.57
52.48	52.48	54.49	3.70	3.70
52.41	52.41	54.49	3.82	3.82
52.34	52.34	54.49	3.94	3.94
52.28	52.28	54.49	4.06	4.06
52.22	52.22	54.49	4.18	4.18
52.15	52.15	54.49	4.29	4.29
52.09	52.09	54.49	4.41	4.41
52.03	52.03	54.49	4.52	4.52
51.96	51.96	54.49	4.64	4.64
51.90	51.90	54.49	4.75	4.75
51.84	51.84	54.49	4.86	4.86
51.78	51.78	54.49	4.97	4.97
51.72	51.72	54.49	5.08	5.08
51.67	51.67	54.49	5.18	5.18
51.61	51.61	54.49	5.29	5.29
51.55	51.55	54.49	5.40	5.40
51.49	51.49	54.49	5.50	5.50
51.44	51.44	54.49	5.60	5.60
51.38	51.38	54.49	5.70	5.70
51.33	51.33	54.49	5.80	5.80
51.28	51.28	54.49	5.90	5.90
51.22	51.22	54.49	6.00	6.00
51.17	51.17	54.49	6.09	6.09
51.12	51.12	54.49	6.18	6.18
51.07	51.07	54.49	6.28	6.28
51.02	51.02	54.49	6.37	6.37
50.97	50.97	54.49	6.45	6.45
50.93	50.93	54.49	6.54	6.54
50.88	50.88	54.49	6.63	6.63
50.83	50.83	54.49	6.71	6.71
50.79	50.79	54.49	6.79	6.79
50.75	50.75	54.49	6.87	6.87
50.71	50.71	54.49	6.95	6.95
50.67	50.67	54.49	7.02	7.02
50.63	50.63	54.49	7.09	7.09
50.59	50.59	54.49	7.16	7.16
50.55	50.55	54.49	7.23	7.23
50.52	50.52	54.49	7.29	7.29
50.48	50.48	54.49	7.36	7.36
50.45	50.45	54.49	7.42	7.42
50.42	50.42	54.49	7.47	7.47
50.39	50.39	54.49	7.52	7.52
50.36	50.36	54.49	7.58	7.58
50.34	50.34	54.49	7.62	7.62
50.31	50.31	54.49	7.67	7.67
50.29	50.29	54.49	7.71	7.71
50.27	50.27	54.49	7.74	7.74
50.25	50.25	54.49	7.77	7.77

Table 2: Error estimation from both PROSPERTM mixture and liquid densitie

Parameter	Value
Operating Frequency (Hz)	57
Pump Depth (ft)	6166
Number of Stages	40

Table 3: ESP modeled parameters in PROSPER™

would also like to thank Rabea Ahyed, Saad Al-Zahrani and Ali Al-Zahrani for their support in the real-time data configuration and modeling.

Abbreviations

ft - Feet
km - Kilometers
m - Meters
% - Percentage
ρ_{liq} - Liquid density in Ibs/ft^3
ρ_{mix} - Fluid mixture density in Ibs/ft^3
ρ_o - Oil density in Ibs/ft^3
ρ_w - Water density in Ibs/ft^3
A - Oil density at standard conditions in Ibs/ft^3
B - Water density at standard conditions in Ibs/ft^3
D_{DIS} - ESP discharge pressure depth in ft
Error - Error between the mixture and liquid densities in %
F_{WHT} - Flowing wellhead temperature in degrees Fahrenheit
F_{WHP} - Flowing wellhead pressure in psig
P_{DIS} - ESP discharge pressure in psig
Psig- Pound per square inch gauge
ESP- Electric Submersible Pump
GVF- Gas Volume Fraction
IWC- Intelligent Well Completion
PVT- Pressure Volume Temperature
PI- Process Information
SCADA - Supervisory Control and Data Acquisition
W/C - Water Cut in %

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Triazine-based Scavengers: Can They Be a Potential for Formation Damage?

By Yaser K. Al-Duailej, Mohammed H. Al-Khaldi and Saleh A. Al-Kulaibi.

Abstract

Hydrogen sulfide (H_2S) scavengers have been used extensively in different field operations, such as drilling and acid stimulation treatments. Typically, H_2S scav- engers are preliminarily designed to react effectively at different in-situ conditions. For example, triazine-based scavengers are designed for neutral-high pH conditions, while aldehyde-based scavengers are intended for low pH conditions; however, reaction products of these scavengers with H_2S could lead to potential formation damage.

The efficiency of two triazine-based H_2S scavengers were investigated over a wide range of parameters: solution pH value and temperature and exposure time. Additionally, the effects of both scavenger concentration and its ratio to H_2S gas on the scavenging capacity were explored. In this work, the scavenger concentration varied from 1 vol% to 5 vol%, with reaction temperatures up to 50°C.

Earlier studies have shown that, at low pH, triazine-based scavengers have a very low efficiency in scav- enging H_2S because the hydrolysis rate of triazine is faster than the reaction rate with H_2S. Nonetheless, in this study, it was found that a long exposure time between triazine-based scavengers and H_2S can result in significant scavenging efficiency even at low pH values. Doubling the exposure time had almost doubled the amount of scavenged H_2S in acidic solutions. In addition, this work, for the first time, highlights the possibility of calcium sulfide (CaS) precipitation in spent acid containing H_2S scavengers. This precipitation has been observed when low scavenger concentrations were used in spent hydrochloric (HCl) acid. This article provides optimum design parameters that allow for more effective use of H_2S scavengers without causing the formation of CaS scale.

Introduction

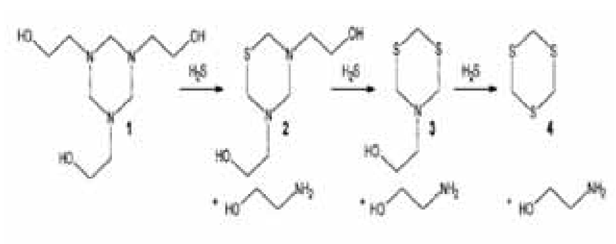
Hydrogen sulfide (H_2S) is a hazardous and toxic gas that leads to worker fatality at concentrations as low as 10 parts per million (ppm). Throughout the oil and gas industry, the safety precautions and regulations against H_2S have been thoroughly applied to ensure the safety of personnel and equipment. Nonetheless, H_2S can also impair the formation permeability by creating precipitations that plug the pore throats. For example, iron sulfide (FeS) has been reported to precipitate when H_2S is mixed with spent acid solutions containing dissolved iron ions[1-3]. Therefore, removal of H_2S content from formation or flow back fluids had become a necessity. There are many techniques to remove H_2S, and one of these techniques is using H_2S scavengers.

H_2S scavengers are chemicals that favorably react with H_2S gas to eliminate it and produce environmental friendly products. These products depend on the type and composition of the scavenger and the conditions at which the reaction takes place. Certain scavengers produce solids, such as metal based scavengers, while others produce soluble products, such as triazines[4-8]. Therefore, for a certain recipe, choosing the proper scavenger is as imperative as its function. In well stimulation treatments, the products of the reaction between H_2S and a scavenger should not damage the formation by creating precipitation or hindering functions of another additive. Mainly, triazine based scavengers have been extensively used in stimulation treatments to remove H_2S from flowed back fluids.

During stimulation treatments, the efficiency of triazine based H_2S scavengers is susceptible to conditions, such as pH, temperature and exposure time[9-11]. Additionally, other factors, such as H2S/scavenger stoichiometry, can affect the reaction of triazine based H_2S scavengers with H_2S. For example, increasing the pH from 0 to 7 has amplified the scavenging capacity by an average of 176%. This is a result of the hydrolysis rate, which increases with acidity[12, 13]. Therefore, the main objectives of this study are: (1) investigate the scavenging capacity of two triazine based H_2S scavengers, namely: T-1 and T-2, (2) assess the effect of temperature, scavenger concentration, and exposure time on the performance of T-1 and T-2 H_2S scavengers, (3) explore the efficiency of the two subject H_2S scavengers in live and spent hydrochloric (HCl) acid solutions, and (4) verify the concern of calcium sulfide (CaS) scale formation.

Theory

Triazine based scavengers are water soluble and mainly consist of hexahydro-1,3,5-tris(2-hydroxyethyl)-sym-triazine, or triazine. This chemical is well-known for its high affinity towards H_2S molecules10. Theoretically, triazine reacts with H_2S at a 1:3 molar ratio. In other words, triazine based scavengers have a theoretical scavenging capacity of three moles of H_2S per one mole of triazine. Triazine reacts with H_2S stepwise as shown in Eq. 1:



(1)

The reaction between triazine and H_2S is a substitution reaction and it undergoes three stages, where the first stage is the easiest and the last one is the most difficult[12, 13]. As shown in Eq. 1, first, the triazine (compound 1) molecule reacts with one molecule of H_2S to produce 2,2-(1,3,5-thiadiazinane-3,5-diyl)diethanol (compound 2). Then, compound 2 reacts with a second molecule of H_2S to produce 2-(1,3,5-diithiazinan-5-yl)ethanol (compound 3). Finally, compound 3 reacts with a third molecule of H_2S to produce 1,3,5-trithiane (compound 4). At each reaction stage, 2-aminoethanol is produced as a byproduct[12]. The energy required for the first triazine-H_2S substitution stage is the lowest required reaction energy. Higher energy is required to drive the triazine-H_2S reaction and further substitution stage to occur[8]. For example, the energy required to drive triazine-H_2S reaction to produce compound 4 is higher than that required in producing compound 3. Therefore, driving the reaction to completion necessitates exceptional conditions to provide chances for compound 3 to further react with H_2S.

This type of triazine is only soluble in aqueous solutions, be it acidic, basic or neutral. There are other types of triazines that are soluble in aqueous solutions and miscible with hydrocarbons, such as 2,2',2"-(hexahydro-1,3,5-triazine-1,3,5triyl)triethanol; however, in this work, triazine refers to hexahydro-1,3,5-tris(2-hydro-xyethyl)-symtriazine. The reactivity of triazine with H_2S varies with different pH values, where it is maximum at high pH and minimum at low pH. This is mainly attributed to the hydrolysis of triazine at different pH values[12]. At low pH, the hydrolysis rate is fast and competing with the reaction rate of triazine with H_2S. In contrast, the hydrolysis rate of triazine is slow at high pH, giving the chance for triazine to react with H_2S. Besides the hydrolysis reaction, the solubility of H_2S in aqueous solution has an effect on its reaction with triazine.

H_2S solubility in pure water has been determined at various temperatures and pressures. It has been reported that the solubility of H_2S in water increases with pressure increase while it decreases with temperature. For example, the solubility of H_2S in water increased from 0.0875 to 1.996 moles/kg when the pressure was increased from 1 to 60 bar, while it decreased from 0.4430 to 0.2613 moles/kg when temperature was increased from 303.15 to 333.15 K. Additionally, the solubility of H_2S in aqueous solutions is affected by the solution pH value.

H_2S is a weak acid and it dissociates stepwise, as shown in Eqs. 2 and 3:

$$H_2S \rightarrow H^+ + HS^- \quad pKa = 7.022 \tag{2}$$

$$HS^- \rightarrow H^+ + S^{2-} \quad pKa = 13.90 \tag{3}$$

Figure 1 shows the distribution of different H_2S species

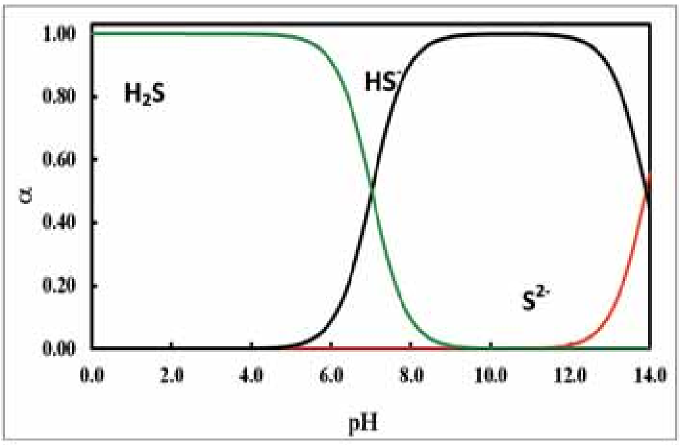


Fig. 1. The distribution of different H_2S species as a function of solution pH value.

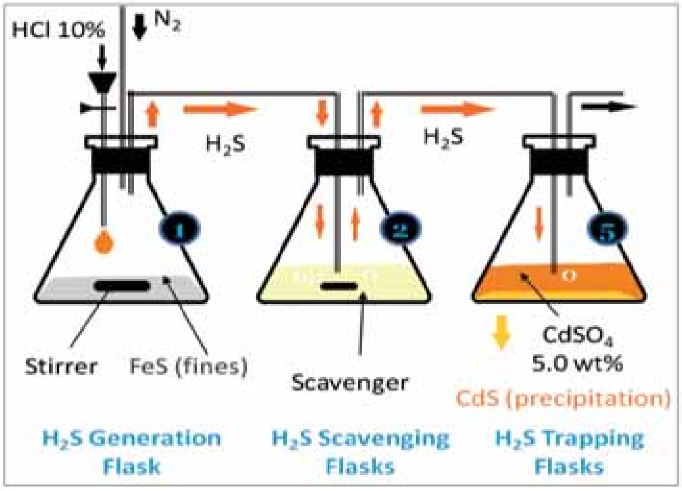


Fig. 2. Experimental setup for the scavenging efficiency experiment.

as a function of solution pH value. At pH values below 6, H_2S is the dominant specie while at pH values between 7 and 12; HS^- is the dominant molecule, which dissociates to S^{2-} at pH values above ~ 13. Based on this, it can be concluded that H_2S solubility is low in acidic solutions and it increases as the pH value in- creases, especially above 7-8. This trend will have an effect on the performance of triazine reaction with H_2S, as will be discussed later.

Experimental Work

Materials

HCl acid was obtained from SigmaAldrich and diluted to 10 wt%. FeS with 99% purity was ground into less than 150 µm. H_2S scavengers (T-1) and (T-2) were provided by two service companies, and they were used as received. Cadmium sulfate hydrate ($3CdSO_4{\cdot}8H_2O$) was used as received from Riedel-de Haën. Calcium carbonate ($CaCO_3$) with 99.0% purity was used as received from Spectrum. All solutions were prepared using distilled water with a resistivity greater than 18 M.cm at 25°C.

Experimental Procedure

To determine the scavenging capacity of an H_2S scav- enger, a known amount of H_2S was generated by re- acting 5 grams of 10 wt% HCl acid with 1 gram of FeS. Generated H_2S was passed through an aqueous solu- tion, with different pH values and concentrations of the subject scavenger. Excess H_2S gas was trapped in a 3 wt% $CdSO_4$ solution as cadmium sulfide (CdS) precipitation. The experimental setup is illustrated in Fig. 2. In all experiments, the quantity of FeS and the concentrations of other used chemicals were fixed, unless otherwise mentioned. The capacity of each triazine based scavenger was determined based on FeS and precipitated CdS.

In another set of experiments, the scavenger solution was divided into two, three or four flasks, instead of one. This was intended to extend the exposure time between H_2S gas and the investigated scavenger. Additionally, the scavenger solutions were heated to 50°C to assess the effect of temperature on the performance of each scavenger.

Results and Discussions

Several experiments were conducted to assess the performance of both T-1 and T-2 triazine based scavengers. The effects of solution pH value, scavenger concentration, exposure time and temperature were investigated. The capacity of these two scavengers was evaluated at pH values of (0-7), scavenger concentration up to 50 gallon per thousand gallons (gpt), and temperatures up to 50°C.

Scavenger Concentration and Solution pH Value

Using one reaction flask, different 10 wt% HCl acid solutions, with a pH value of 0 and varying T-1 con- centrations, were reacted with nearly 0.0115 moles of H_2S. Table 1 and Fig. 3 show the scavenging capacity of these solutions as a function of T-1 concentration. It was noticed that the scavenging capacity was pro- portional to the T-1 concentration in acidic solution. The lowest scavenging capacity was 18.87% at 5 gpt of T-1, while the highest performance was 66.43% at 50 gpt. A similar trend was observed when T-2 was used, Table 2 and Fig. 3. For example, a scavenging capacity

Scavenger (gpt)	FeS (initial)		FeS (remaining)		Gen. H_2S Moles	CdS		Scavenged H_2S (moles)	Scavenging Efficiency, %
	gram	moles	gram	moles		gram	moles		
5	1.01	0.011489	0.47	0.006505	0.006143	0.72	0.004984	0.001159	18.87
10	1.02	0.011603	0.39	0.006827	0.007166	0.69	0.004776	0.002391	33.36
20	1.01	0.011489	0.38	0.007959	0.007166	0.51	0.003530	0.003636	50.74
25	1.01	0.011489	0.38	0.007959	0.007166	0.51	0.003530	0.003636	50.74
30	1	0.011375	0.31	0.006945	0.007849	0.64	0.004430	0.003419	43.56
40	1	0.011375	0.4	0.004381	0.006825	0.39	0.006994	0.004126	60.45
50	1	0.011375	0.42	0.009160	0.006598	0.32	0.002215	0.004383	66.43

Table 1. Scavenging efficiency of different concentrations of T-1 at pH=0

Scavenger (gpt)	FeS (initial)		FeS (remaining)		Gen. H_2S Moles	CdS		Scavenged H_2S (moles)	Scavenging Efficiency, %
	gram	moles	gram	moles		gram	moles		
5	1.01	0.011489	0.4	0.006436	0.006939	0.73	0.005053	0.001886	31
10	1.01	0.011489	0.39	0.007474	0.007053	0.58	0.004015	0.003038	43.07
20	1.01	0.011489	0.45	0.008374	0.006370	0.45	0.003115	0.032550	51.1
25	1.01	0.011489	0.37	0.009205	0.007280	0.33	0.002284	0.004996	68.63
30	1.01	0.011489	0.37	0.008790	0.007280	0.39	0.002699	0.004581	62.92
35	1.01	0.011489	0.34	0.008167	0.007621	0.48	0.003322	0.004299	56.41
40	1.01	0.011489	0.37	0.007821	0.007280	0.53	0.003668	0.003612	49.61
45	1.01	0.011489	0.35	0.008374	0.007508	0.45	0.003115	0.004393	58.5
50	1.01	0.011489	0.4	0.008928	0.006939	0.37	0.002561	0.004378	63.1

Table 2. Scavenging efficiency of different concentrations of T-2 at pH=0

Scavenger (gpt)	FeS (initial)		FeS (remaining)		Gen. H_2S Moles	CdS		Scavenged H_2S (moles)	Scavenging Efficiency, %
	gram	moles	gram	moles		gram	moles		
10	1.01	0.011489	0.37	0.007059	0.007280	0.64	0.004430	0.002850	39.15
30	1.02	0.011603	0.41	0.007657	0.006939	0.57	0.003945	0.002994	43.14
50	1.01	0.011489	0.41	0.009828	0.006825	0.24	0.001661	0.005164	75.66

Table 3. Scavenging efficiency of different concentrations of T-1 at pH=4 (By adding $CaCO_3$)

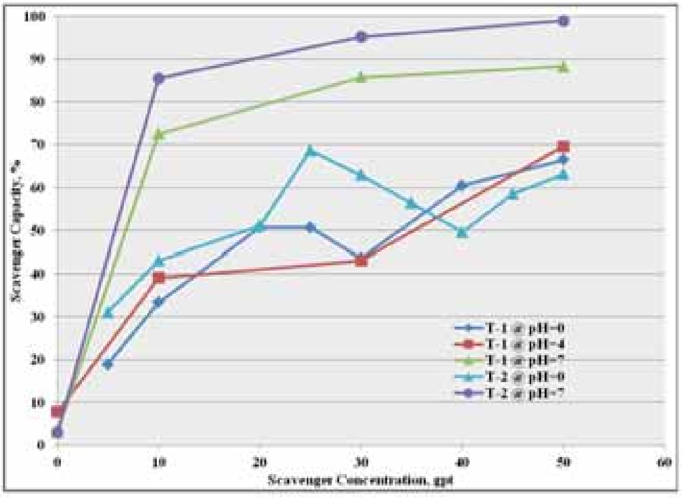


Fig. 3. Scavenging efficiency of T-1 and T-2 at different pH values.

Scavenger (gpt)	FeS (initial)		FeS (remaining)		Gen. H_2S Moles	CdS		Scavenged H_2S (moles)	Scavenging Efficiency, %
	gram	moles	gram	moles		gram	moles		
10	1	0.011375	0.38	0.009437	0.007053	0.28	0.001938	0.005115	72.52
30	1	0.011375	0.4	0.010406	0.006825	0.14	0.000969	0.005856	85.8
50	1	0.011375	0.43	0.010614	0.006484	0.11	0.000761	0.005723	88.26

Table 4. Scavenging efficiency of different concentrations of T-1 at pH=7 (distilled water).

Scavenger (gpt)	FeS (initial)		FeS (remaining)		Gen. H_2S Moles	CdS		Scavenged H_2S (moles)	Scavenging Efficiency, %
	gram	moles	gram	moles		gram	moles		
10	1.01	0.011489	0.42	0.010520	0.006711	0.14	0.000969	0.005742	85.56
30	1.01	0.011489	0.44	0.011178	0.006484	0.045	0.000311	0.006172	95.2
50	1.01	0.011489	0.43	0.011420	0.006598	0.01	0.000069	0.006528	98.95

Table 5. Scavenging efficiency of different concentrations of T-2 at pH=7 (distilled water).

of 31% was achieved at the T-2 concentration of 5 gpt, while the scavenging capacity reached nearly 63% at 50 gpt of T- 2. For both T-1 and T-2, a 50% scavenging capacity occurred when nearly 20 gpt of scavenger was used. Besides scavenger concentration, the solution pH value had an effect of the scavenger performance.

Tables 3 and 4, and Fig. 3 show the effect of the solution pH value on the performance of the T-1 scavenger. In the first set of experiments, $CaCO_3$ was used to spend HCl acid and increase pH value of solution to 4. These spent acid solutions with varying T-1 concentrations were reacted with nearly 0.0115 moles of H_2S. At scavenger concentration of 10 gpt, an increase in the scavenging capacity of T-1 by 17% was observed when the solution pH was raised from 0 to 4. A more noticeable increase occurred in the scavenging capacity of T-1 when it was used in distilled water (pH =7). The scavenging capacity nearly doubled when the pH value was raised from 0 to 7, at a T-1 concentration of 10 gpt. A similar effect of pH was also noticed when T-2 was used. The scavenging efficiency results of T-2, in Table

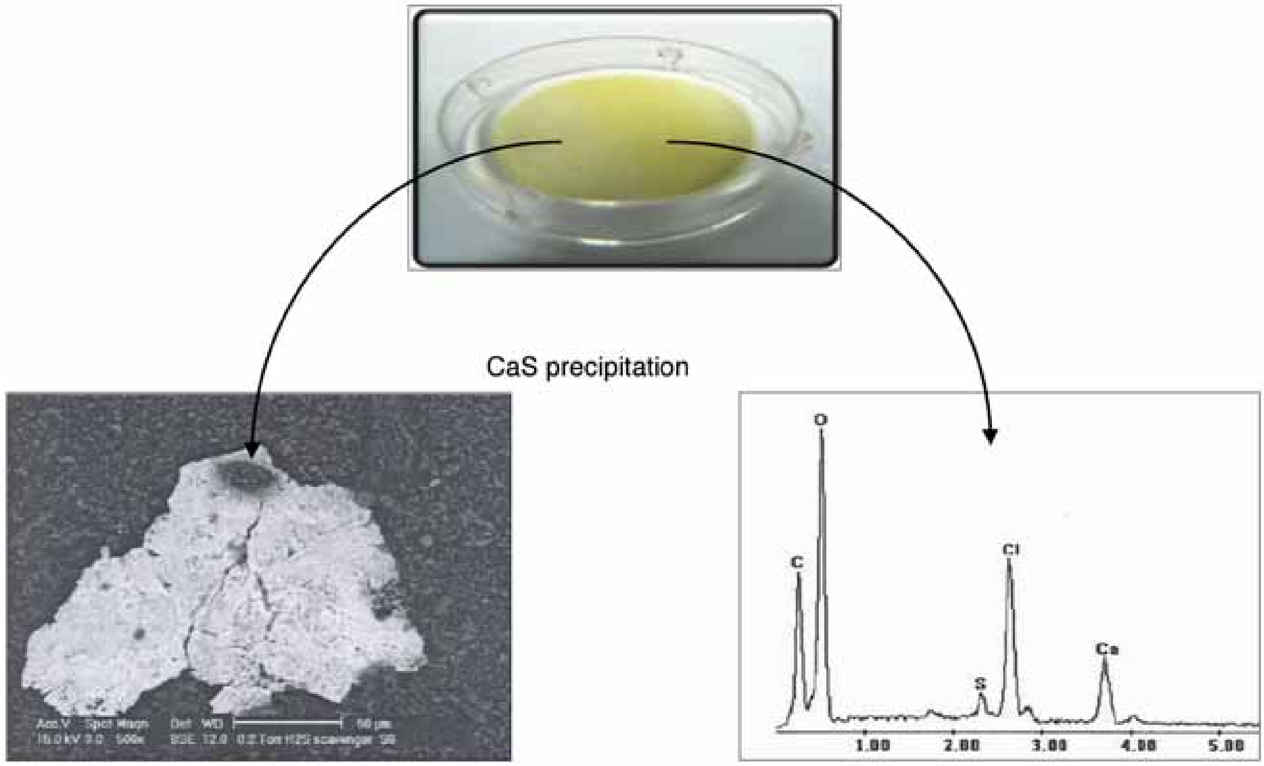


Photo 1. Backscattered electron image and corresponding EDS X-ray spectrum for the precipitation found when 10 gpt T-1 was used at pH=4 (spent HCl acid).

5 and Fig. 3, show a significant increase at a pH of 7. At 10 gpt, the enhancement in scavenging capacity was almost 2.5 times the capacity at a pH of 0. At 30 gpt and 50 gpt concentrations, the effect of the pH was not as significant, almost 1.5 times the capacity at a pH of 0.

As previously mentioned, as HCl acid spends due to reaction with formation rocks, the pH of acid will increase enhancing the performance of triazine based H_2S scavengers; however, CaS precipitation was noticed in the spent HCl acid solution containing a H2S scavenger concentration of 10 gpt, Photo 1. At 30 and 50 gpt, no precipitation was observed. This indicates that there is a critical concentration of H_2S scavengers below that where CaS precipitation will occur.

Effect of Exposure Time

The scavenging capacity of both T-1 and T-2 was low at a pH of 0, and moderately high at a pH of 7. This can be mainly attributed to either the effect of competing hy- drolysis reaction of triazine at low pH values, or to the low solubility of H_2S gas at low pH values, which will minimize the contact time between H_2S and the scavenger. Therefore, in several experiments, the effect of exposure time on scavenging capacity was investigated.

To allow the scavenger more time to contact H_2S, the 10 wt% HCl acid solutions, containing varying concentrations of scavenger, were divided into several flasks, Figs. 4, 5 and 6. Excess H_2S that did not react in the first flask had another chance of reacting with the scavenger in the following flask. The amount of generated H_2S gas and the concentration of H_2S scavengers were equal to those used in the first set of experiments (one reaction flask).

Table 6 and Fig. 7 show the evident effect of increasing contact time on the capacity of the T-1 scavenger at a pH of 0. The scavenging capacity, at 10 gpt of T-1 and a pH of 0, increased by twofold when the reaction solution was divided into two and four flasks. It increased from nearly 39% to almost 60% when the contact time between T-1 and H_2S was nearly doubled. No further increase was noticed when the contact time was increased (four reaction flasks). Similarly, the same trend was noticed when T-2 was used.

The results of T-2 in Table 7 and Fig. 7 show the evident effect of increasing contact time on the capacity of the scavenger at a pH of 0. The scavenging capacities from the modified setup, Fig. 5, are almost twice the results from the original experimental setup, Fig. 1. In Table 8, the scavenging efficiencies of T-1 and T-2 were high in terms of scavenged moles of H_2S. The scavenged H_2S

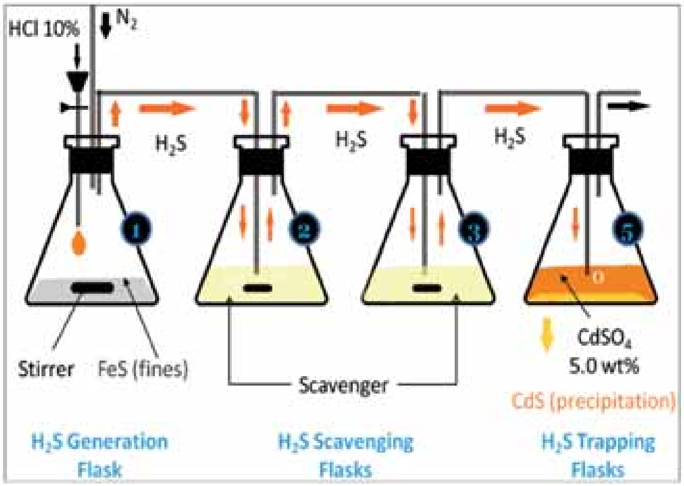


Fig. 4. Modified experimental setup for the scavenging efficiency experiment, where the scavenger solution is divided into two flasks

Scavenger (gpt)	FeS (initial)		FeS (remaining)		Gen. H_2S Moles	CdS		Scavenged H_2S (moles)	Scavenging Efficiency, %
	gram	moles	gram	moles		gram	moles		
10	1.01	0.011489	0.36	0.008582	0.007394	0.42	0.002907	0.004487	60.68
20	1.01	0.011489	0.34	0.011143	0.007621	0.05	0.000346	0.007275	95.46
30	1.01	0.011489	0.37	0.011178	0.007280	0.045	0.000311	0.006969	95.72

Table 6. Scavenging efficiency of different concentrations of T-1 at pH=0 with the scavenger solution divided into two flasks.

moles are double the moles scavenged when 2x flasks were used. That was a result of doubling the amount of all chemicals in these experiments, including the scavengers. Nonetheless, all concentrations and ratios were constantly maintained. The results in Table 8 verified the results obtained in Table 7. Based on these results, it is clear that the earlier noticed low scavenging capacity of both scavengers was due to the low solubility of H_2S in acidic solutions, which minimized its contact with the scavenger. Subsequently, given adequate contact time, the scavenging capacity of both scavengers reacted nearly 90% of the time, even at a low pH value of 0. Based on average contact time reached during these laboratory experiments, under field conditions of high pressure, adequate contact time between the used scavenger and H_2S will be reached.

Effect of Temperature

The effect of increasing temperature on the scavenging efficiency of T-1 and T-2 was also investigated. The scavenger solution was heated to 50°C and results were compared to the results generated at room temperature. Figure 8 shows an overall slight increase in the scavenging efficiencies of T-1 and T-2 at a higher temperature and a pH of 0. This slight increase reflects the minimal effect of temperature on the reaction of triazine based scavengers and H_2S.

Conclusions and Recommendations

The capacity of two triazine based scavengers, namely T-1 and T-2, was extensively investigated at different conditions. It was evaluated as a function of scavenger concentration, solution pH value, temperature, and exposure time. Based on the results of this evaluation, the following were concluded:

1. Triazine based scavengers are efficient H_2S scavengers at aqueous medium, even at acidic conditions (pH=0), given enough exposure time.

Under field conditions of high pressure, adequate contact time between the used scavenger and H_2S will be reached.

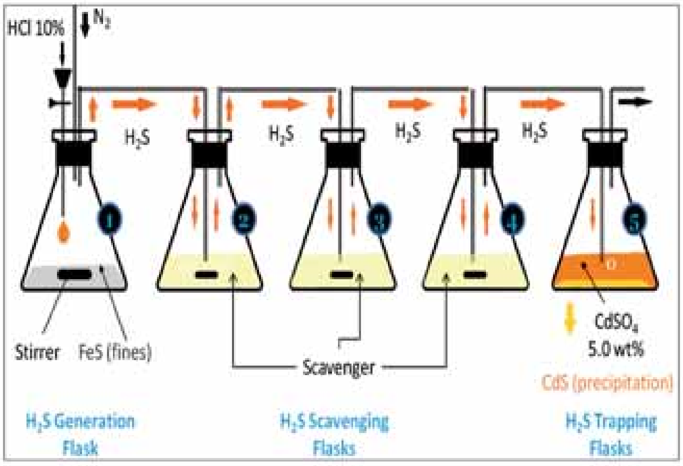


Fig. 5. Modified experimental setup for the scavenging efficiency experiment, where the scavenger solution is divided into three flasks.

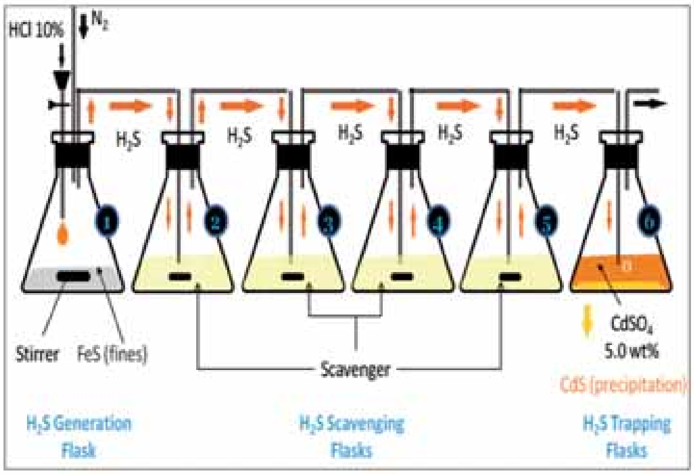


Fig. 6. Modified experimental setup for the scavenging efficiency experiment, where the scavenger solution is divided into four flasks.

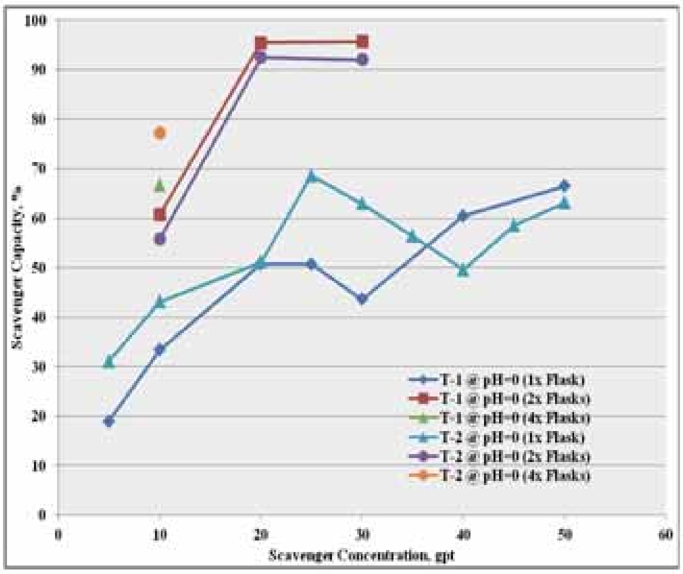


Fig. 7. Scavenging efficiency of T-1 and T-2 at pH=0 and different exposure time

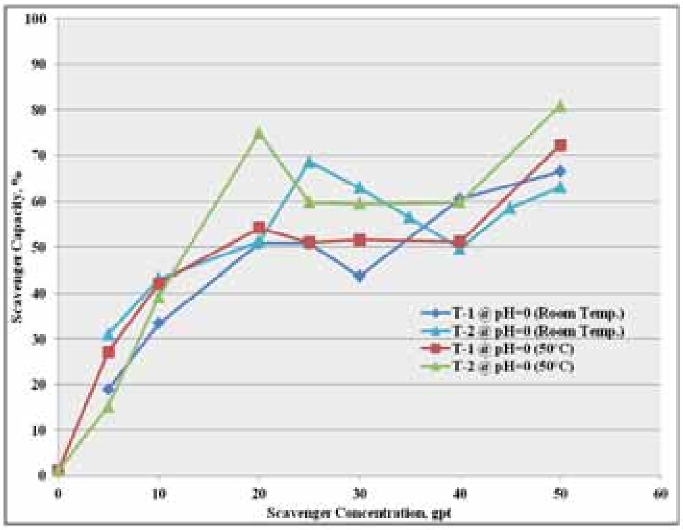


Fig. 8. Scavenging efficiency of T-1 and T-2 at pH=0 in room temperature and 50°C using 1x flask.

2. The capacity of the T-1 scavenger increased with the solution's pH value. With minimal contact time, the scavenger capacity at 10 gpt reached nearly 70%-85%.

3. At a low concentration, 10 gpt of T-1 scavenger, CaS can form in spent acid solutions.

4. Temperature has minimal effect on the performance of triazine based scavengers, up to 50°C.

Based on the findings of this study, the following were recommended:

1. Optimum concentration of triazine based scavengers in acidic solutions was found to be 20 gpt. At this concentration, the scavenging capacity reached nearly 90%. Additionally, at 10 gpt of T-1, CaS scale was witnessed in spent acid solutions.

2. Optimum concentration in neutral solutions, i.e., a pH of 6, was found to be 10 gpt. At this concentration, the scavenging capacity reached nearly 70%-85% and no precipitation was observed.

3. The concentration of the scavenger can be in- creased to 30 gpt if the H_2S mole percent is very high. This is to prevent the damaging precipitation, CaS, from forming.

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Scavenger (gpt)	FeS (initial)		FeS (remaining)		Gen. H_2S Moles	CdS		Scavenged H_2S (moles)	Scavenging Efficiency, %
	gram	moles	gram	moles		gram	moles		
10	1.01	0.011489	0.35	0.008167	0.007508	0.48	0.003322	0.004185	55.75
20	1.01	0.011489	0.44	0.011004	0.006484	0.07	0.000484	0.005999	92.53
30	1.01	0.011489	0.4	0.010935	0.006939	0.08	0.000554	0.006385	92.02

Table 7. Scavenging efficiency of different concentrations of T-2 at pH=0 with the scavenger solution divided into two flasks.

Scavenger (gpt)	FeS (initial)		FeS (remaining)		Gen. H_2S Moles	CdS		Scavenged H_2S (moles)	Scavenging Efficiency, %	Scavenger
	gram	moles	gram	moles		gram	moles			
10	2.01	0.022864	0.84	0.018434	0.013309	0.64	0.004430	0.008879	66.72	T-1
10	2.01	0.022864	1.05	0.020372	0.010920	0.36	0.002492	0.008428	77.18	T-2

Table 8. Scavenging efficiency of 10 gpt of T-1 and T-2 at pH=0 with the scavenger solution divided into four flasks.

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Biographies

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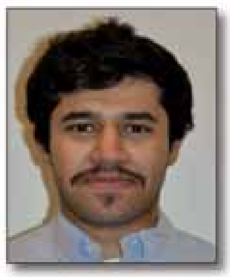

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Representative Prediction of Geological Facies and Rock-Type Proportion Distributions with Novel Beta Field Characterization

By Dr. Jose A. Vargas-Guzman and Dr. K. Daniel Khan.

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Abstract

Successful drilling of new wells in carbonate and clastic reservoirs must maximize the probability of intercepting the target rocks. Wells are planned on 3D cellular computer models where each cell represents a rock's 3D element and its petrophysical properties. Geocellular modeling of rock categories is based on the prior 3D depiction of facies proportions. The proportions are a measure of probability, and they are uncertain at nonsampled locations. Therefore, proportions must be modeled as random variables p(x) at each location *x*. Experience shows that proportions do not appear to follow the Gaussian, power or lognormal distribution; instead, numerical experiments on real geological phenomena led to the discovery that conditional proportions behave as Beta distributed variables. The theoretical implications of Beta distributions are not discussed in this article, but one finding is that classical geostatistics cannot be directly used on the proportions. Therefore, a novel transform was devised to project the proportion random variables to a Gaussian domain. This enables the use of classi- cal spatial statistical methods. The correct conditional means and variances of the Beta variables are recovered after the transformation back to proportions through Riemann integration. Obtaining a theoretically correct estimate of the uncertainty in the local facies proportions allows risk analysis with high confidence for such activities as drilling infill development wells. Some complementary examples are presented with discussions. In addition, Beta distributed rock proportions allow geological modelers to explore the uncertainty in facies trends from mapping or seismic attribute interpretation in a quantitatively correct way that is straightforward, yet avoids the restriction of a multivariate Gaussian model.

Introduction

Successful placement of wells for hydrocarbon reservoir development must maximize the proportion of target rocks intercepted by the wells. The critical problem of well placement is that carbonate or clastic rock categories are uncertain at undrilled locations; therefore, the unknown proportions of rocks (i.e., geological heterogeneity) must be treated as a probability of rock occurrences. Proportions can be measured at a single well; for example, the vertical proportion is the ratio of permeable target rock thickness and the total thickness of the formation penetrated by a vertical well. Some information about the proportions of rocks at undrilled locations also may be available from seismic facies[1, 2]. The main limitation is the vertical resolution; as a consequence, thinner beds and heterogeneity due to small rock bodies are not visible from seismic. Reconstructions of the depositional facies environments with sequence stratigraphy[3, 4] may allow for soft information about the probabilities of finding certain facies with new wells. Sequence stratigraphy identifies key bounding surfaces as maximum flooding surfaces and sequence boundaries, typically delineating rock bodies of predictable grain size trends in three dimensions. Sediment supply, accommodation space and the boundary conditions of basin paleo-topography and sea level, however, are highly uncertain, resulting in nonunique and subjective mapping, which is unreliable at higher resolution due to the sparse data constraints. Dynamic modeling, based on flow mechanics, considers the sources of sediment supply, depositional constraints, subsidence and tectonics[5], e.g., the Sedsim approach, and also yields highly nonunique solutions due to uncertainties in the boundary conditions[6]. In addition, facies bodies cannot be simulated to match the high resolution data of the current wells. These limitations necessarily result in insufficient local precision for detailed field development decisions. Direct interpolation of proportions from the wells is unrealistic because the geometry of rock bodies is usually complex and produces nonlinear relations between proportions. Consequently, the quantitative integration of seismic, sequence stratigraphy and current well data is necessary to gain information about facies distributions and rocks expected in the subsurface. The prediction of rock proportions from seismic and sequence stratigraphy depends on realistic probability distributions of such proportions and the spatial variations inferred from contemporary trend analogs.

Facies trends are nonstationary constraints used to control the local, prior probability distribution of facies proportions in geostatistical indicator simulations[7, 8]. A rarely recognized aspect of facies modeling is that a trend constraint often has the largest impact on the outcome of indicator facies simulations and the resultant flow simulations[9]. In addition, decisions that depend on localized risk cannot be made on the basis of a realization of the facies' assemblage; the variable of interest is the local proportion or probability of the target facies.

Predicting the probability of the occurrence of specific geologic facies at undrilled locations is equivalent to predicting conditional proportions from indicators, which are the typical random variables used for representing the occurrence of a specific category at a given location

$$i(x;c_k) = \begin{cases} 1, & \text{if category } c_k \text{ at location } x \\ 0, & \text{otherwise} \end{cases} \quad, k = 1, \dots K$$

for K categories. The mean indicator for each category, taken over some volume of interest (e.g., a wellbore), is a propotion, Eqn. 1:

$$p_k = E[i(x;c_k)] = \frac{1}{n}\sum_{1}^{n} i(x;c_k) \qquad (1)$$

This proportion can be interpreted as a probability in the sense that it describes the frequency of occurrence of elements of a given size (e.g., well log or core samples) over the volume or thickness of interest. The variance of the facies proportions is written as:

$$var(p_k) = E[(p_k - E[p_k])^2] \qquad (2)$$

Equations 1 and 2 are summary statistics of the distribution of the facies indicator. The random variable of interest here is the facies indicator proportion pk at each spatial location x conditional to the surrounding data. At drilled locations, the probability p_k is known, within measurement error, while at undrilled locations, operators must estimate the probability density function (pdf) of p_k to predict the most likely rock distribution in any new planned well. If such a probability distribution is fairly represented by the first two moments, then estimating the mean $E(p_k)$ and variance $var(p_k)$ is critical for any risk assessment of drilling due to the uncertainty in the geological heterogeneity.

The Beta distribution has been presented in the geostatistical literature as a means for modeling the global uncertainty in categorical facies proportions[10,11] and for modeling change-of- support effects in categorical facies proportions[12]. The objective of this article is to show practical evidence demonstrating that the distribution of the proportions of facies over a field corresponds to a field of correlated Beta distributed random variables. The importance of this finding is that an understand- ing of the probability distribution law governing the spatially correlated proportions of rocks allows construction of more realistic models for facies proportions. The article also proposes a practical methodology to model facies proportions while accounting for closure constraints, and it provides a sound tool to study proportions in facies analogs and outcrops.

Evidence for Beta Distributed Facies Proportions

Gaussian Projection Experiment

The original insight that conditional proportions are Beta distributed variables was obtained from straightforward experiments, explained next. It is well-known that indicator statistics are defined for any continuous attribute by counting the frequency of samples below a cutoff value,

$$i(x;z_k)=\begin{cases}1, & \text{if the attribute } p \text{ at location } x \text{ is } p\le p_k\\ 0, & \text{otherwise}\end{cases}$$

For example, the proportion of rock samples having poros- ity less than or equal to a specified cutoff defines the cumulative proportion for that indicator class. The collection of all such indicator proportions defines the global or unconditional cumulative probability distribution for the attribute, $F_g(z)$. A conditional cumulative distribution function (ccdf) of the attribute, say, at a specific location in the field is denoted $F_c(z|\ \cdot)$. The conditional mean and variance are a function of the surrounding information (·). In the simplest case, all of the conditional distributions are the same shape as the global distribution. Consider a standard, normally distributed variable z. We project the z values corresponding to a ccdf, $F_c(z|\ \cdot)$, onto the uniform [0,1] cumulative probability axis of the z cdf, $F_g(z)$, Fig. 1. For the unconditional variate z, the result is, of course, the uniform [0,1] distribution; however, for any conditional distribution $F_c(z|\ \cdot)$, it yields the conditional random variable of the conditional cumulative proportions, $p_\beta\ (x)=F_g(z|(x)\ \cdot)$. The result is a set of conditional histograms of the [0,1] valued probability, or the cumulative proportion random variable $p_\beta\ (x)$, one for each conditional random variable projected, Fig. 1. These density functions have nonuniform shapes ranging systematically from a symmetric function about the median skewed distributions towards the extremes. The conditional distributions in Fig. 1 are all a perfect fit with Beta pdfs, which have the following form:

$$f(x;\alpha,\beta)=\frac{\Gamma(\alpha+\beta)}{\Gamma(\alpha)\Gamma(\beta)}p^{\alpha-1}(1-p)^{\beta-1},\qquad p\in[0,1]\qquad(3)$$

where r(.) is the gamma function, p is the proportion, (α) and (β) are shape parameters.

The shape parameters α and β of the Beta distribution are related to the mean and variance of proportions by the following well-known relations:

$$\alpha=\hat{p}\left[\frac{\hat{p}(1-\hat{p})}{var(\hat{p})}-1\right],\qquad \beta=(1-\hat{p})\left[\frac{\hat{p}(1-\hat{p})}{var(\hat{p})}-1\right]\qquad(4)$$

The exercise shows evidence that conditional distributions of proportions, or probability random variables, are not uniform. This result is not confined to the Gaussian distribution model; the same result is observed when the global and conditional z-cdfs are lognormal distributed or when they follow the F-distribution. The possibility of conditional proportions being Beta distributed variables needs to be tested with real physical phenomena. Such an experiment is described next.

Analog Image Analysis Experiment

To test whether the facies proportions in a real complex geological field are Beta distributed, the experiment utilized an image of a carbonate tidal flat environment. The satellite image is available from NASA's Earth Observatory website as photograph ISS026-E-5121. A small area of the image was selected for the experiment,

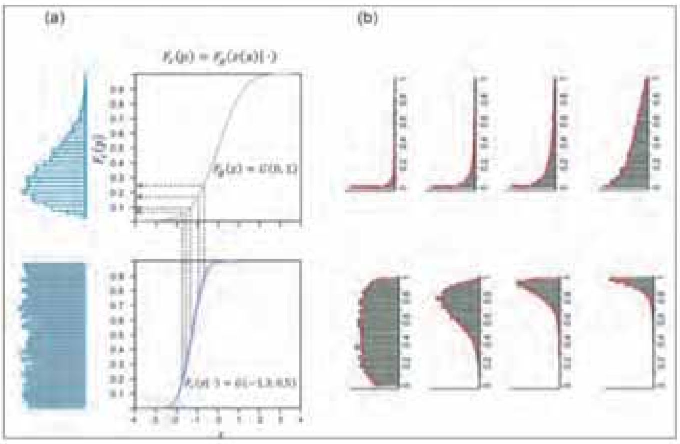

Fig. 1a. Distributions of conditional probability are generated by projection onto the unconditional uniform [0,1] axis of the standard normal Gaussian CDF..

Fig. 1b. Distribution of proportions from eight conditional Gaussian distributions with mean values (-2.5, - 1.64, -1.27, -0.67, 0, 0.67, 1.27, 1.64) and variance (0.9, 0.9, 0.9, 0.9, 0.9, 0.5, 0.5, 0.5), read from top left.

Fig. 2. Sampling local proportion distributions in a realistic geological field can be accomplished in a model-based setting with images generated through an object-based geostatistical model or a forward process rules-based, pseudo-physical model. Alternatively, to avoid model-based constraints on the analysis, simulated annealing can be used to generate multiple subtly different versions of the reference image while retaining the overall character of the original image, as was done here.

The satellite image, Fig. 2, was first classified into three categories based on its red, green and blue spectrum; truncations on the first two principal components of the spectrum were sufficient for this classification. The image classifications plausibly correspond to (1) grainy facies, (2) reef facies, and (3) tidal flat facies, Fig. 2. Although the image classification is not perfect, likely having some misclassification errors and lacking in facies discrimination, it suffices for the purposes of the experiment. The simulated annealing program SASIM13 was used to perturb the pixel maps of the principal components, subject to constraints on the variograms, histograms and smoothed versions of the reference pixel maps. Each pair of realizations of the principal components' pixel maps was truncated according to the same criteria and assembled into a single realization of the categorical facies assemblage. A total of 500 indicator maps were processed. Taking the average indicator for each facies class yielded three facies proportion maps, which served as the reference proportion maps, Fig. 3. These proportion maps were then perturbed using SASIM to generate multiple equiprobable realizations of the facies proportions. It is these final facies proportion realizations that we were interested in sampling at specific locations to observe the distributions of local conditional proportions.

The frequency histograms of the local proportions at four different locations, ranging from low to high valued proportions for Facies 1, is shown in Fig. 4. As before, these histograms are fit well by Beta distributions: no other distribution family provides a better fit. These results, taken together with the results from the analytical experiments, provide convincing empirical evidence that spatial conditional proportion fields are comprised of correlated Beta distributed random variables. Figure 4 is consistent with the geologists' intuition, as deposition of facies is affected by distance to the sea, topography and physical and chemical gradients, meaning that facies conform to nonstationary geological heterogeneity, which cannot have uniform frequency.

Fig. 2. NASA Earth Observatory photograph ISS026-E-5121, Bahamas, with a small cutout classified into three facies categories for image analysis.

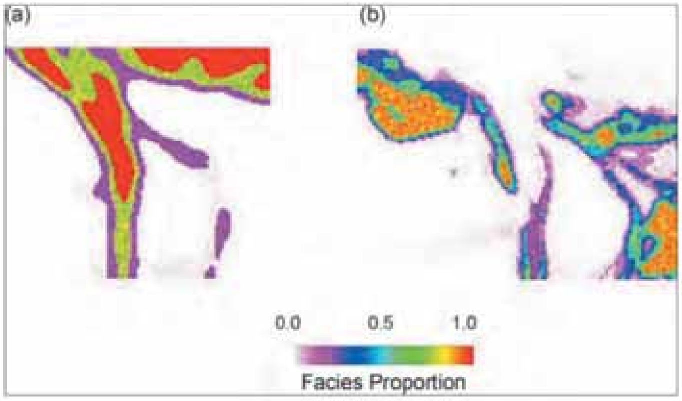

Fig. 3. Reference facies indicator proportion maps for the (a) grainy and (b) reef facies, as generated by simulated annealing perturbations of the classified image in Fig. 2.

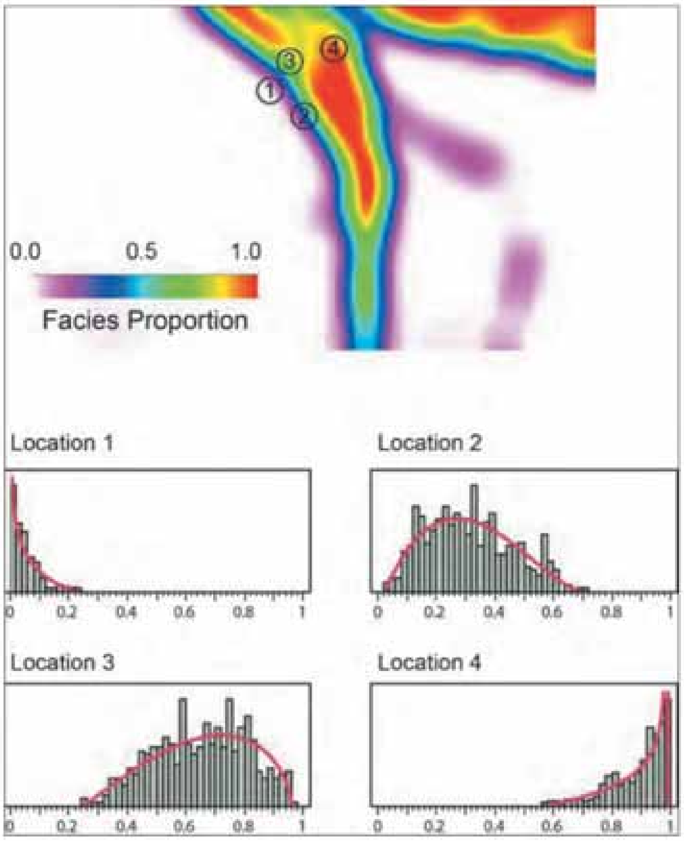

Fig. 4. Annealing results on reference facies proportion map of Fig. 3a provides empirical evidence that local distributions of uncertainty in facies proportions are Beta distributed.

Modeling Beta Distributed Facies Proportions

Transforming Correlated Beta Proportions

The finding that a Beta random variable comprises the conditional facies proportion in the likelihood distribution determined in analog satellite images is a powerful one for hydrocarbon exploration and for the probability of finding selected rocks in the subsurface. One can now obtain a robust, possibly non-symmetric, conditional pdf at each unsampled location in the field. Note that the shape of each pdf depends on the proportion mean $\hat{p}$ and variance $var(\hat{p})$. Therefore, all that is needed is an estimate of the local mean and variance, which can be obtained by kriging. A significant complication, however, is that the variable shapes of the local Beta distributions entail nonlinear correlations between the proportion random variables at any two locations[14]. This means that a stationary covariance model, or variogram, cannot account for the spatial correlation underlying the proportion field. Dealing with such nonlinear and nonstationary correlations is highly impractical at best and would require sophisticated estimation programs. A practical solution is to find a transformation function that converts the Beta random variables to random variables that follow a symmetric distribution function, regardless of the conditional moments.

A simple and novel transformation was devised. The logic leading to the proposed transform is based on basic principles of indicators. In summary, it was found that the logarithm of the variance of indicators, is a squared Gaussian. Note that the variance of indicators,

$$ln\left(\frac{p-p^2}{0.25}\right)$$

is a second order measure. The linearization transformation, □(*p*), is

$$y = \varphi(p) = \pm\sqrt{\left|ln\left(\frac{p-p^2}{0.25}\right)\right|}, \quad -\infty < y < \infty; \qquad (5)$$
$$y < 0 \text{ for } p < 0.5, \text{and } y > 0 \text{ for } p > 0.5)$$

From Eqn. 5, a back transformation is constructed after solving the quadratic relation between the proportion and the Gaussian random variable. This is

$$p = \varphi^{-1}(y) = \frac{1}{2} \pm \frac{1}{2}\sqrt{1 - exp(-(y)^2)} \qquad (6)$$

Note that p is the target Beta distributed proportion random variable, and q=(1-p) is the proportion random variable for the complementary event. Both results are directly obtained from solving Eqn. 6, and the closure condition $q+p=1$ is automatically granted.

Because this nonlinear transformation cannot be applied to expected values without introducing a strong bias, the expected values for the moments must be evaluated using Riemann's integral for power random variables[15]. This yields

$$E[p^m] \cong \int_{-\infty}^{\infty} \left(\frac{1}{2} \pm \frac{1}{2}\sqrt{1 - exp(-(y^2))}\right)^m \frac{1}{\sigma\sqrt{2\pi}} exp\left(-\frac{(y-\hat{\mu}_y)^2}{2\hat{\sigma}^2_y}\right) dy \qquad (7)$$

The corrected mean, , and variance, , are used to compute the Beta parameters, as indicated in Eqn. 4.

The transformation of Eqn. 5 is exactly Gaussian for any symmetric Beta distribution, ($\alpha = \beta$) , for integer Beta parameters. For asymmetric Beta distributions, (α π β) , the transformation is approximate, but yields results that are very close to Gaussian[14]. The estimated Beta parameters based on the approximate Gaussian transformation are therefore not exact, because Eqn. 7 considers a true Gaussian variable while the random variable given by the transformation of Eqn. 5 is not exactly Gaussian. In practice, the errors in the estimated Beta parameters are sufficiently small that they can be neglected, since they do not result in a large change in the shape of the Beta distribution.

Estimation and Simulation Workflow

The first step in a practical workflow is to average the facies indicator well logs by zone for the proportion data, $p_k(x)$, at each well location. In 3D averaging, one can use moving windows and transform these $p_k(x)$ data to $y(x)$ data via Eqn. 5. One then computes the experimental variogram of the $y(x)$ data and fits a combination of valid nested models[13]. Optionally, one can transform any secondary constraints on the local seismic facies and facies maps, or other secondary data, to y-scores to make use of collocated cokriging or kriging with a locally varying mean[7, 13].

Simulation of conditional Beta probability fields (P-fields) proceeds via the conventional sequential simulation approach, with the Riemann back transformation of parameters, Eqn. 7, and Gaussian forward transformation of simulated proportions, Eqn. 5, as embedded steps.

1. Initialize a path through the nodes.

2. Compute a kriging mean $\hat{\mu}_y(x)$ and variance $\hat{\sigma}^2_y(x)$ at an unsampled location.

3. Back transform the estimates, $\hat{\mu}_y(x)$ and $\hat{\sigma}^2_y(x)$, with the Riemann integration, Eqn. 7, to obtain the Beta ccdf parameters α and β , Eqn. 4.

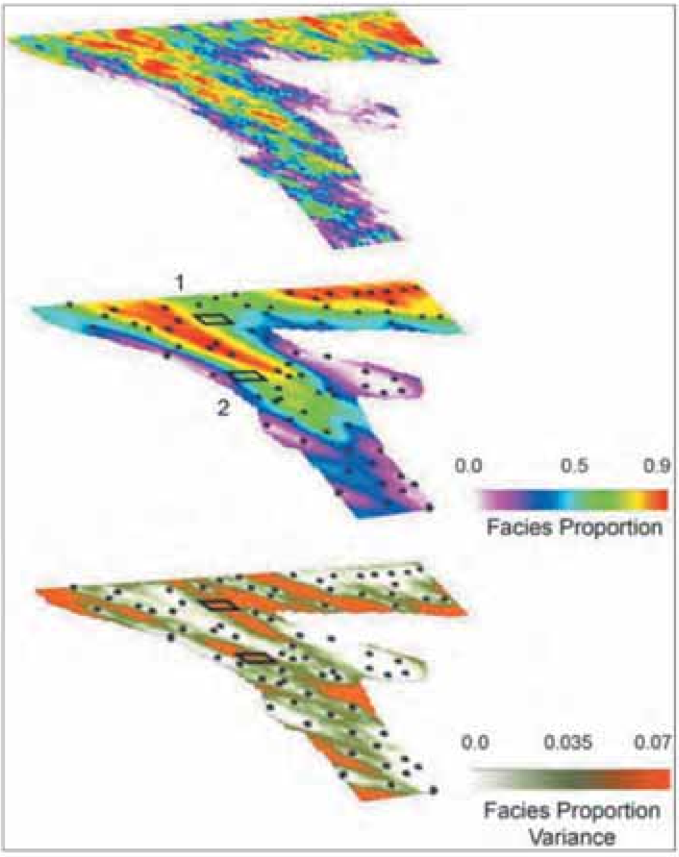

Fig. 5. Simulated facies proportions (top), expected value map (center) and conditional variance map (bottom), summarizing the local distributions of uncertainty in facies proportions based on a sparse sample dataset of the reference facies map of Fig. 3a. Proposed infill drill locations are shown as boxes 1 and 2.

4. Draw a random number, $^{u}{}_{p}$ [0,1], from the uniform pdf and obtain the inverse of the local Beta distribution as a simulated realization, *p(x)*, of the random variable $p_\beta(x)$.

5. Transform the simulated value *p(x)* to *y(x)* using Eqn. 5, and return to step 2 to iterate on the estimation of parameters for the next location. Repeat steps 2-5 until all nodes have been visited. The public domain software SGSIM[13] is easily modified to accommodate the proposed algorithm. The inverse of the local Beta ccdf is obtained by implementing the algorithm[16]. After the proportion data are transformed into the pseudo-Gaussian variables, nonlinear relations will have vanished, but nonstationary relations may still be present and need proper handling with known workflows. The goal of the typical workflow is to decompose the deterministic trend and stochastic residuals as separate components[17].

Discussion of Practical Examples

Risk Quantification in Development Well Drilling

Consider the grainstone facies proportion map of Fig. 4 and a corresponding dataset sampling from the reference map, Fig. 5. The proportion data have been transformed via Eqn. 5, and the sample variogram of the y-scores is fit by an anisotropic model. We identified two proposed well locations, Fig. 5, for evaluation. Suppose a minimum thickness criterion for an economic well requires that no less than 50% of the reservoir thickness be the grainstone facies. A direct kriging and simulation approach to the facies proportions should be avoided because of the nonstationary and nonlinear correlations between Beta distributed random variables, as pointed out in previous sections. The recommended approach is to simulate with transformations a reasonably large number of facies proportion realizations, since we are estimating the local Beta distribution parameters sequentially; one such realization is shown in Fig. 5. The ensemble mean (E-type) and the conditional variance map for proportions of the target facies provide an estimate of the local Beta distributions at each unsampled location, including our proposed well locations, Fig. 6. Location 1 has a conditional mean and facies proportion variance of 0.55 and 0.06, respectively, while location 2 has

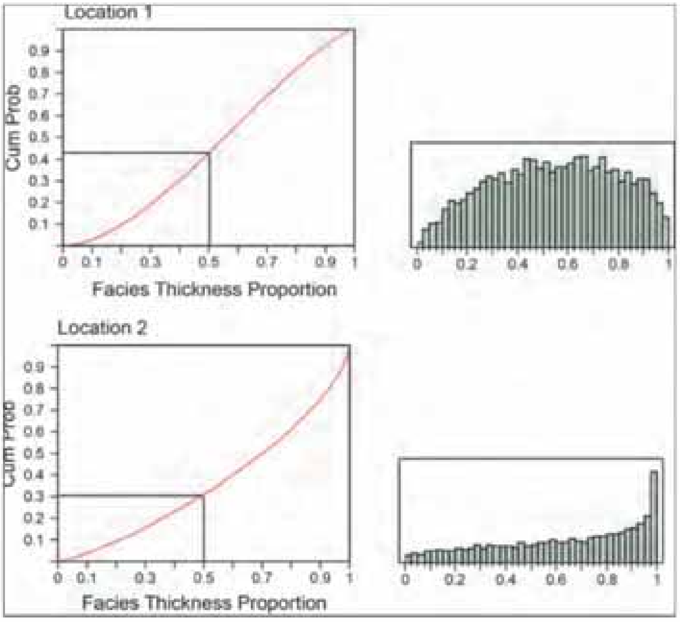

Fig. 6. Distributions of local facies proportions for proposed infill drill locations 1 and 2 of Fig. 5. The probability of encountering less than the minimum facies thickness criterion of 0.5 of total reservoir thickness is 42% at location 1 and 31% at location 2.

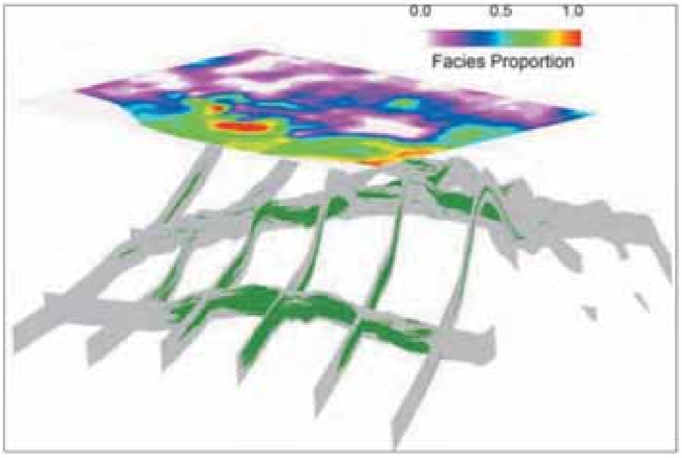

Fig. 7. Facies proportion trend map of a key reservoir quality indicator facies (top) and the example indicator simulation constrained by this map (bottom).

a conditional mean and facies proportion variance of 0.60 and 0.08, respectively. While the estimated expected proportion and the uncertainty are not very different between the two locations, it is clear that the distribution shape will affect the risk, as estimated from a given cutoff on the ccdf. The proposed Beta simulation methodology can be expected to accurately characterize the local uncertainty distributions. A traditional Gaussian simulation technique would easily yield incorrect results. This is because the underlying conditional proportion field comprises a nonlinear Beta P-field that does not respond to a stationary variogram model. In addition, a conventional normal scores transformation and simulation under a multivariate Gaussian model would not be equivalent to the proposed approach. The multivariate Gaussian model forces the necessary limitations of asymptotic independence of the extremes, or maximum entropy. In comparison, a correlated field of Beta distributed random variables does not correspond to such behavior and appears to be much closer to reality, as inferred from empirical results.

Uncertainty of the Facies Trend Model

Most reservoirs are nonstationary in the local facies proportions. All geostatistical algorithms for facies modeling require the specification of the nonstationary facies trend models (i.e., hand drawn facies maps from sequence stratigraphy and/or seismic). The facies trend model is typically considered a prior, low frequency constraint, yet the trend model tends to dominate the character of the simulated facies, and it may over-constrain the variability between realizations, which may unrealistically reduce the uncertainty in the geology. Therefore, there is arguably strong motivation to introduce a realistic level of uncertainty in the facies proportion map or model. In this example, Beta fields enable a more realistic uncertainty evaluation.

Probabilistic inverse calibration techniques for iterative conditioning to nonlinear response variables in this example make use of correlated Beta proportion fields. Consider a reservoir quality indicator variable that has a significant impact on production response, Fig. 7. The proportion map of this facies is simulated as previously described, and the ensemble average and conditional variance maps yield the local Beta probability distributions, Fig. 8. We selected a vector of seed or master locations from which to propagate perturbations to the local proportions (e.g., as per the method of Capilla, Rodrigo and Gómez-Hernández[18]). The impact of the propagations is a function of the shape of the correlated local Beta distributions. Convergence to a set of optimal perturbations to the reference facies proportion map that minimize the mismatch between observation data and reservoir simulation response yields a trend realization that may be considered the best prior constraint for a 3D indicator realization of the facies model, Fig. 9. The proposed novel idea here is to consider a field of correlated Beta variables as a robust, nonlinear probabilistic model for exploring the geological uncertainty in inversion problems. The same approach is applicable to blind tests or

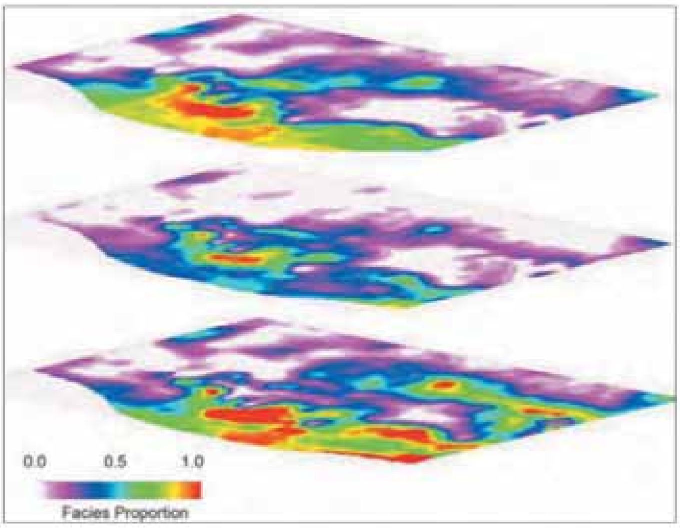

Fig. 8a. Estimated facies proportion mean and variance maps with eight locations selected to propagate perturbations to the facies probability field.
Fig. 8b. Distributions of uncertainty at the selected control nodes.
Fig. 8c. Impact of probability perturbation of +0.2 units to the mean on the local facies proportion at control nodes 2 and 3

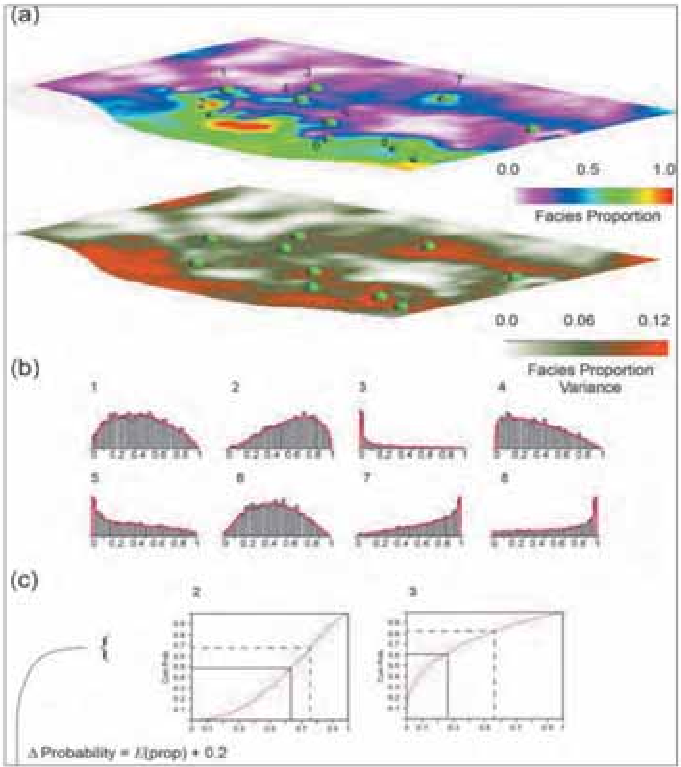

Fig. 9. Three realizations of the facies proportion map generated by correlated field of probability perturbations from control node locations. These proportion maps have a dominant impact on the simulated facies model.

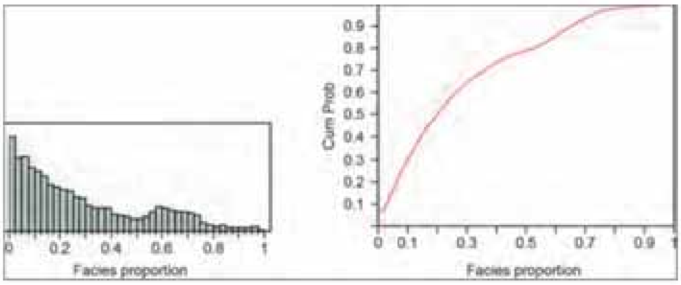

Fig. 10. Global distribution of facies proportions used to map the transformation to normal scores and back in a classical Gaussian simulation approach.

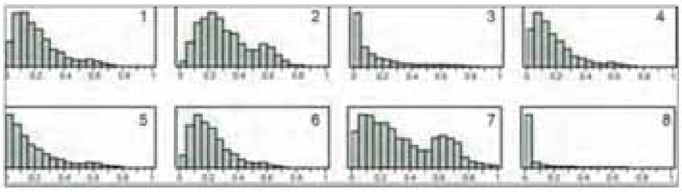

Fig. 11. Local conditional probability distributions of proportions modeled with a classical Gaussian approach and anamorphic back transformed through the global distribution. Compare with the actual Beta distributions of Fig. 8b.

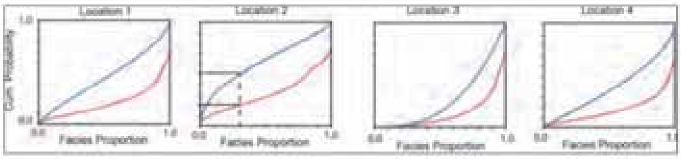

Fig. 12. Comparison of Beta-modeled (blue) and (anamorphic-back-transformed) Gaussian-modeled (red) conditional distributions of local facies proportions at the first four locations in Fig. 8b and Fig. 11. The Gaussian-modeled and back-transformed probability distributions are systematically biased low and underestimate the risk of exceeding a cutoff in facies proportion. At location 2, the example shows a difference in risk of 30%.

can be used to cross-validate the goodness of trend facies maps, with new wells compared to multiple facies models with the same prior facies maps. Errors detected with new wells can be utilized to modify the stratigraphic interpretation. More generally, this example offers evidence that a statistically correct way to handle correlated local uncertainties in categorical facies proportions, or continuous P-fields with no simplifications, should be to use Beta distributions of proportions.

Comparison to Gaussian Assumption: Consequence in Terms of Risk and Cutoffs

The standard approach to solving geostatistical estimation problems of continuous attributes is to consider a rank preserving transformation (i.e., anamorphosis) of the data to normal scores, kriging and simulation in Gaussian space, followed by back transformation of the simulated values through the global cumulative distribution function (CDF) of the attribute[13]. Riemann integration in Eqn. 7 shows that a back transformation of the Gaussian moments to obtain the Beta moments is not the same as the transformation of the Gaussian to Beta random variables. As an analogy, lognormal geostatistics shows that the exponential of the Gaussian mean is not the mean of the lognormal. Therefore, the Beta estimation and simulation approach of conditional proportions is not equivalent to a transformation mapped or tabulated through the global CDF. In fact, the global CDF has no practical utility in nonstationary fields, such as facies proportions. Consider that the distributions of Fig. 8b are various local proportion distributions from specific locations in a field with a global histogram, Fig. 10. The field is assumed to be quasi-stationary in the Gaussian domain, but it is nonstationary in the Beta domain. Assume that the estimated Beta distributions, according to the proposed methodology, are very close to the true Beta distributions, as previously discussed. Now consider Gaussian modeled local proportion distributions followed by a back transformation on the global CDF, as per the classical rank transform approach. Note that the conditional means and variances of the intermediate y-scores, Eqn. 5, of the Beta simulation methodology are directly comparable to the Gaussian parameters obtained by classical Gaussian simulation before back transformation. After classical back transformation of the normal scores is performed, the local conditional distributions of the proportions do not correspond to the expected Beta distributions, Fig. 11. The only case where the classical Gaussian approach would yield closely comparable results is where the global distribution of proportions is approximately uniform. This will most often not be the case in practice. The consequence is a potentially severe bias of the predicted risk towards the low end, or an underestimation of the net reservoir occurrence based on cutoffs, Fig. 12. This example shows that modeling Beta distributed proportions will enable a more realistic risk analysis and prediction of local proportions of net reservoir pay defined from facies, rock-type classifications, or fluid saturation and petrophysical property cutoffs. The recommendation is to avoid the standard practice of using transformations from the global distribution because facies proportions are nonstationary. In addition, the nonlinear effect on expectations, implicit in Riemann's integral, is not included in such transformations.

Discussion and Conclusions

This article is a unique contribution on the use of the Beta probability distribution as a law for natural facies proportions. Evidence is presented to show that the conditional probability distributions of facies proportions in a geological field are actually comprised of correlated Beta random variables. This appears as a new discovery in geostatistics and opens up a more general framework for the study of correlated conditional probability. A particularly important insight leading to a new development in correlated Beta processes is that a field of correlated conditional probability is highly nonlinear and therefore cannot be directly modeled by stationary, second order Gaussian models. This addresses a long-standing gap in geostatistics pertaining to the covariance structure of a P-field[19-21]. Although this work is focused on categorical facies proportions, the concept applies to the P-field of continuous attributes as well[11].

Facies proportions are defined over a volume within which the facies indicators are distributed. To simplify the illustration, the examples here deal with 2D maps, representing the averaging of facies indicators over a reservoir horizon. The concepts and methods presented here, however, apply equally in characterizing the variability of facies proportions in 3D. For example, facies proportions inferred from 3D seismic at a coarser resolution average the underlying geological vertical heterogeneity, which needs to be restored using the proper variance and shape of pdfs for proportions.

Most often we are interested in multiple facies, for K=1, ..., K facies categories. The expected proportions must sum to unity, which is known as the closure condition. One can estimate the local distributions of uncertainty in the facies proportions pair-wise by lumping categories in a hierarchical estimation work-flow. The multivariate modeling with closure conditions is reported separately.

This contribution clarifies the nature of the distribution of conditional proportions underlying categorical geological facies attributes. Empirical evidence from annealing perturbations onreal images of geology demonstrates that the random variables characterizing the uncertainty in local facies proportions appear to be Beta distributed. Analytical evidence on conditional proportions or cumulative probability gives exact results. Correlated Beta proportion fields are nonlinear, such that the correlation functions between different locations cannot be modeled by classical linear geostatistical methods. In addition, the article offers a completely novel workflow for modeling the proposed Beta fields of facies proportions. A novel transformation of the proportions was developed to transform the variance of indicators in terms of proportion random variables to approximate Gaussian distributions, which respond to a stationary covariance or variogram model. This allows kriging based estimation of the local mean and variance by standard methods, followed by an integral back transformation of the estimated mean and second order Gaussian variance to yield unbiased estimates of the moments of Beta random variables.

Obtaining a theoretically correct estimate of the uncertainty in the local facies proportion allows high confidence in risk analyses for the activities, such as infill drilling of development wells, discussed in the article. In addition, it allows geological modelers to explore the uncertainty of facies trends from sequence stratigraphic mapping or seismic attribute interpretation in a quantitatively correct way that is straightforward – allowing the use of Gaussian kriging, yet without the need for the often incorrect simplification of a multivariate Gaussian spatial field. The claim that the local facies distributions are truly Beta distributed is based on empirical evidence. The proposed methodology for simulating geostatistical fields of Beta random variables is practical and highly valuable in light of the improvements it makes possible over Gaussian approaches when facies or rock proportions are the attributes of interest.

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Biographies

Dr. Jose Antonio Vargas-Guzmán joined Saudi Aramco in 2002 and works as a Senior Consultant with the Reservoir Characterization Department, Geological Modeling Division. During his career, he has been involved in mathematical applications to 3D geological modeling and evaluation, and he is the senior author of many journal papers, book reviews and book chapters; he has received numerous literature citations. The International Association for Mathematical Geology (IAMG) conferred on him the Best Paper Award from the Mathematical Geology journal for his peer-reviewed paper on successive estimation of spatial conditional distributions in 2003. The IAMG also bestowed on him the Best Reviewer Award from the Journal of Mathematical Geosciences in 2007.

Jose Antonio is a former Fulbright and DAAD Scholar. In 1998, he received his Ph.D. degree from the University of Arizona, Tucson, AZ, where he has also served as a research associate, instructor and full-time faculty member. He was granted a graduate scholarship and a post-doctoral fellowship with funding provided by the U.S. Nuclear Regulatory Commission (NRC) and the Department of Energy (DOE), respectively. Also, he was a research fellow in advanced geostatistics at the University of Queensland, Australia. In the 1980s, he served as a Chief Geologist for Société Générale de Surveillance (SGS).

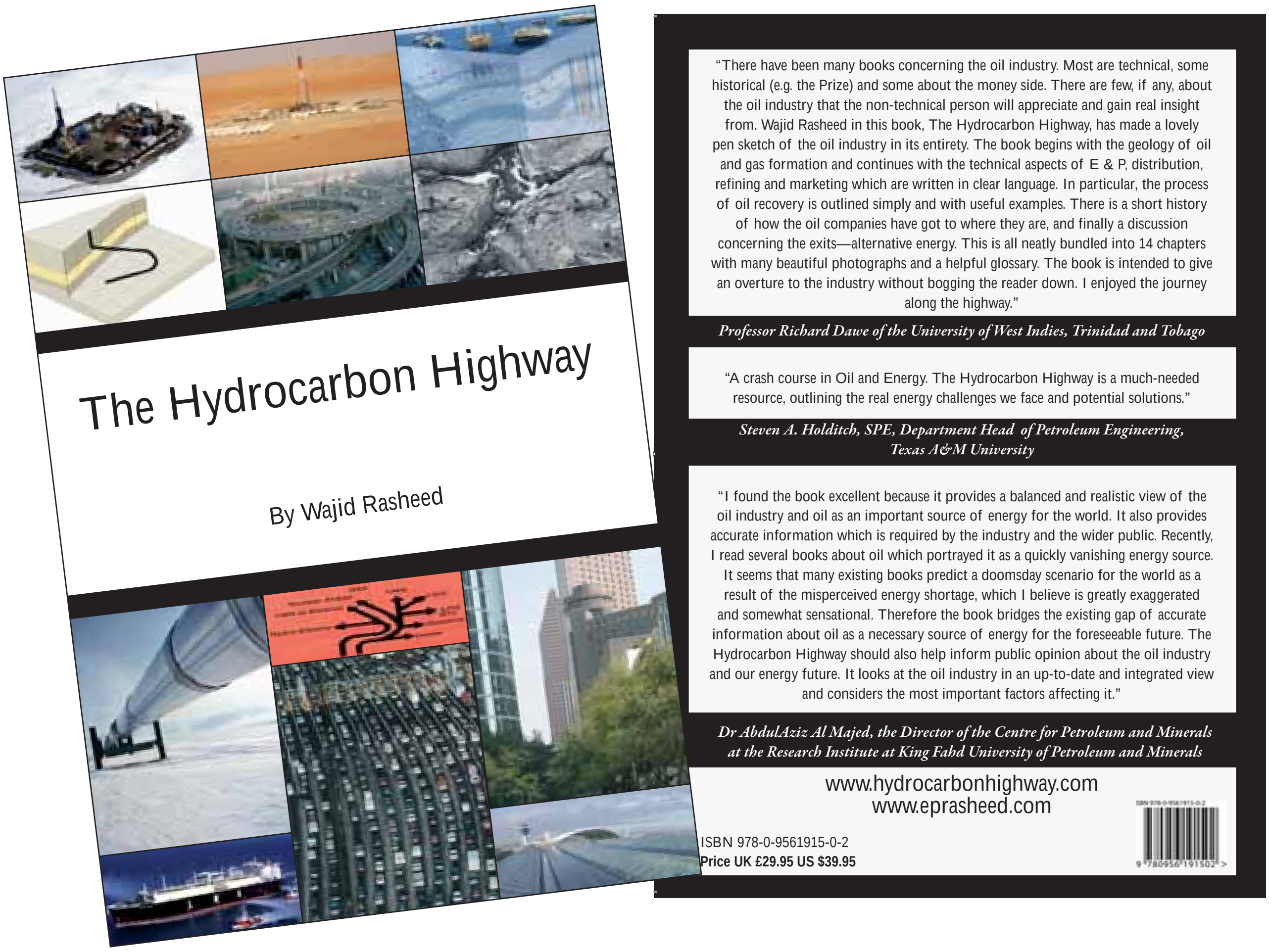
Jose Antonio's current interest is in higher-order petroleum systems. He proposes the inverse reconstruction of complex geological processes and the evaluation of natural resources with estimation and stochastic simulation with higher-order cumulants. Jose Antonio's most outstanding inventions are 3D geological modeling algorithms, such as sequential kriging, stochastic simulation by successive residuals, conditional decompositions, transitive modeling of facies, spatial upscaling of the lognormal distribution, downscaling methods for seismic data with derivatives of the variogram, scale effect of principal component analysis, power random fields, and cumulants for higher-order spatial statistics of complex rock systems and heavy tailed distributions of permeability fields.

Dr. K. Daniel Khan is a Geologist and Numerical Modeler working with the Reservoir Characterization Department in Saudi Aramco. He applies his expertise in heterogeneity modeling for petroleum reservoir characterization using geostatistical and inverse data calibration techniques on various assets within the Kingdom. Daniel has been with Saudi Aramco since June 2010. Prior to this, he worked for the Energy Technology Company of Chevron Corporation in Houston, TX.

In 2001, he received his B.S. degree in Geology from the University of Alberta, Edmonton, Alberta, Canada. In 2006, Daniel received his Ph.D. degree in Hydrogeology, also from the University of Alberta.

He is active in publishing original research and has coauthored an instructional book on geostatistics.

Pregnant Ladies and Fish Bones



Striking oil relies on Exploration and Production processes. This chapter presents standard well planning and construction methods. It concludes with geo-steering, expandable tubulars and digitalisation case histories.

Designer, horizontal and multi-lateral are common well types which are drilled to enable access to hydrocarbon reserves, lower field development costs and improve production. 'Pregnant ladies and fish bones' describe complex twisting well-paths that have become necessary to access and drain numerous reservoirs into a single wellbore[1].

Before the process of well engineering can begin, however, oil companies must complete a series of other activities. In sequential order, these range from geophysical surveys to well planning to drilling and completions. Later, we will present case studies of geo-steering, expandables and digitalisation.

Seismic

X-rays enable doctors to 'see' inside the body and locate injuries without using a scalpel. Similarly, seismic

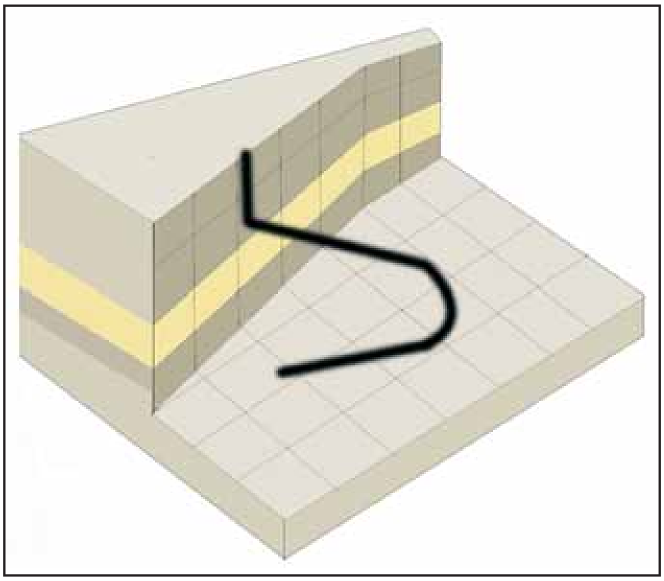


Figure 1 - Pregnant Lady Well Profile

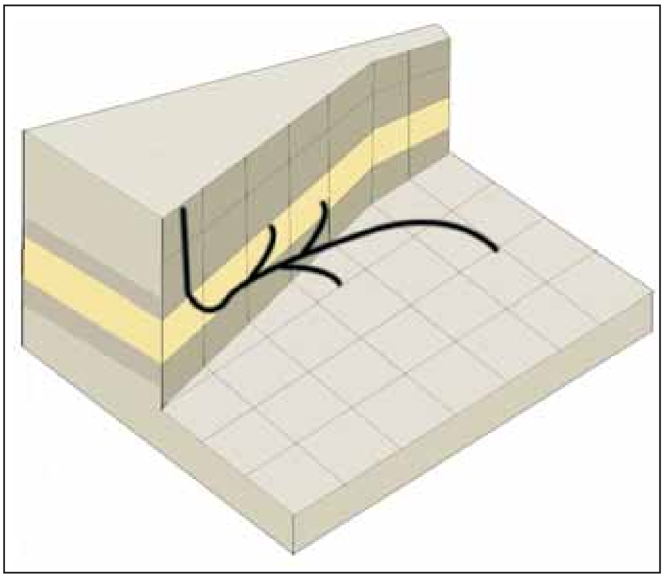


Figure 2 - Fishbone Well Profile

enables scientists to 'see' inside the earth and locate potential hydrocarbon-bearing structures without using a drill bit[2].

An acoustic means of investigating the earth, seismic is used by oil companies to locate potential hydrocarbon-bearing structures within their acreage. Shooting seismic is the first step in reducing the risk accompanying oil and gas exploration. It enables the Geophysical and Geological team (G&G) to 'look' deep into the oil company's acreage and interpret the type and geometry of rocks contained therein.

In this way, hundreds of square kilometres with vertical depths reaching two miles (six km) or more can be imaged without incurring the time, financial

Figure 3 - Seismic Provides An X-Ray Image Of The Earth

> Shooting seismic essentially relies on a 'source' that emits sound waves ranging from 1 to 100 hz, and a 'geophone' that records the reflected waves as they 'bounce' back from different rock formations.

and environmental costs of drilling several dry holes. With diligence, geoscientists will find 'bright spots' – the industry term for a potential hydrocarbon reservoir. Bright spots will often form the basis of top drilling prospects. In this way, seismic allows the rapid and effective imaging of vast surface areas and the pinpointing of reservoir locations and properties. Drilling on bright spots is not a 'slam-dunk' as several International Oil Companies (IOCs) discovered in the early 1970s in offshore Florida. The bright spots were clearly there, but only a drop of oil was found.

Sound Waves

Shooting seismic essentially relies on a 'source' that emits sound waves ranging from 1 to 100 hz, and a 'geophone' that records the reflected waves as they 'bounce' back from different rock formations. This data is mapped by powerful computers using thousands of processors to yield 'processed' seismic information. This information forms 'seismic' sections which usually represent 10 km depths of the earth at a time[3].

The G&G team pores over these sections gaining knowledge of formation thicknesses, locations, beds, dipping planes and the all-important potential oil and gas reservoir. Coupled with advanced visualisation software, it is possible to 'walk through the earth' – a reference to viewing the distribution of rock layers or stratigraphy according to its depth and properties.

Pay-Per-View

As we have seen (*Chapter 6: Properties, Players and Processes*), oil and gas leases may be state or privately-owned tracts either onshore or offshore. In either case, seismic cannot be shot without a permit. There is a rising scale of regulatory demands associated with seismic activity which follows the general rule that offshore seismic (shooting water bottoms) permits are more stringent than those onshore. Locations within nature reserves will have even more demanding permitting criteria.

In all cases, an Environmental Impact Assessment (EIA) will be undertaken by the oil company and submitted to the appropriate environmental regulatory authority for approval. To conduct seismic, a fee is usually paid to the landowner. Prices are determined by adjacent finds, the degree of exclusivity, regulatory burden, general market forces and whether the acreage is private or state-owned.

Needle in a Haystack

Licensed acreage refers to areas where an oil company or group of oil companies has obtained exclusive rights to explore, develop and produce hydrocarbons. Clearly,

Figure 4 - EIA Minimises Disturbances to Animal Life

finding oil and gas is a complex process with greater complexity added by offshore or remote locations and large unexplored blocks.

Waves, whales and winds are just some of the challenges facing a seismic program. Others include sea-currents, sea-traffic, minimising environmental impact and the technical challenges associated with the seismic process itself. These technical challenges are related to receiving clear signals and reducing background noise which can distort seismic data. Accurate seismic saves oil companies millions of dollars that would otherwise be spent in drilling dry holes and reduces the environmental impact of drilling[4].

Environmental Regulations

Regulations governing seismic are comparable in most oil and gas provinces and are based on wider environmental protection laws. The application for consent to conduct or permit seismic is only issued after the EIA considers various factors including disturbance to animal life. In the case of shooting water bottoms, the animals most sensitive to disturbance are cetaceans (marine mammals) such as whales and dolphins (see Figure 4).

Marine Mammal Observers (MMOs) are employed solely to minimise disturbance to cetaceans during seismic activity. For sensitive marine areas, the MMO must also be an experienced cetacean biologist or similar. Often, surveys are required to be conducted during summer months and during daylight; if there is poor visibility such as fog or storm weather, the survey may be stopped.

Regulations state that at least 30 minutes before a seismic source is activated, operators should carefully observe from a high observation platform whether there are any cetaceans within a 1600 ft (487 m) zone of the vessel.

Hydrophones and other specialised equipment may provide further indications of submerged animals, and such equipment is to be used in particularly sensitive areas. If cetaceans are present, seismic sources cannot be activated until the animals have moved away, normally after at least a 20 minute waiting period[5].

Except for sensitive areas, all seismic surveys using a source size of more than 180 cubic inches must follow a slow ramp-up procedure. In other words, irrespective of whether marine mammals have been sighted, acoustic activity should be increased slowly. This can include starting with the smallest air gun and slowly building up. Space does not permit examination of other restrictions and procedures, but seismic activity

> "Although there may be some basic information on formation markers, porosity and permeability, temperatures, and the expected hydrocarbon gas or oil, much more information needs to be predicted such as the reservoir pressure, formation markers, the TVD to the tops of formations, and a range of other pressures."

is controlled and an extensive written report must be sent to the authorities after the survey is completed.

Surface Tow

The most common source of 'shooting water bottoms' is an air gun which releases compressed air into the water generating an acoustic shock wave that travels to the seabed and beyond. Seismic sources are towed behind the seismic vessel slightly beneath the surface of the water.

A streamer is towed behind the vessel on the surface of the sea picking up reflected sound waves. Usually, a streamer contains hundreds of pressure-sensitive hydrophones in a near-buoyant cable that can be 2 miles (3.2 km) or more in length.

A geophone is a type of seismic receiver placed on land or on the seabed that records seismic waves by registering the minute movements of particles. In offshore operations, geophones are configured to record both compression waves (P-waves) and shear waves (S-waves). This is because sound travels through liquids (the sea) as compression waves, while it travels as both compression and shear waves through solids (the earth below the seabed).

Brown and Green Fields

Seismic has evolved greatly over the years and has applications in mature fields as well as the exploratory phases of oilfield development. The industry uses the terms brown and green fields respectively to describe the age of the field. In fact, seismic provides tremendous value during the production of an oilfield and as mature fields start to decline (see *Chapter 9: Mature Fields* for detail).

Deeper reservoirs, or those located below salt, would have been overlooked previously as seismic was not capable of being imaged beneath shallow reservoirs or below formations containing thick layers of salt. Accompanying advances in seismic enable imaging of deep targets, a drilling technology first that has overcome the directional control and drilling torque problems related to drilling 32,800 ft (10,000 m) or more. The current world record depth well is 40,320 ft (12,293 m).

For deeper or sub-salt seismic, two seismic vessels are run together with both shooting and using long streamers. Global Positioning Systems (GPS) are used to keep the two vessels at a known distance and this maintains the required distance between the source and streamer to accurately measure seismic reflections from deep and sub-salt formations. A new technique called 'coil shooting'[6], whereby a single source/acquisition vessel sails in overlapping circles while acquiring data, provides rich-azimuth seismic imaging of deep and sub-salt formations at less than half the cost of traditional means.

'Shooting seismic' is crucial to reducing oil and gas exploration risk because it enables the G & G team to visualise deep inside the earth and locate promising structures without the cost and impact of drilling[7].

4D Seismic

Time lapse or 4D seismic accompanies the lifecycle of an oil and gas asset providing valuable seismic information on the asset as it matures (see *Chapter 9: Mature Fields* for more detail). 4D seismic (the 4th dimension is time) is a technique involving comparison of successive 3D seismic surveys taken over the same area. Geoscientists can detect the effect of fluid migration over time and thus deduce the reservoir's preferential drainage patterns. This information is invaluable in situating additional in-fill wells or altering the pattern of injector wells versus producer wells. In one example, comprising the largest 4D survey ever acquired, the operator (Petrobras) was able to relocate 11 already-planned deepwater well trajectories and plan an additional nine wells for a total of 20 wells affected. The changes saved the company about US $900 million, which would have been the cost of drilling the 11 wells in the wrong place, and it expects to gain considerable profits from the 20 wells drilled in the right place.

Well Planning

Well planning is the process of creating a blueprint for constructing oil and gas wells. Here is a behind the scenes look at the key components of well planning and their interaction[8].

The well plan, a book-like bundle of engineering and legal documents, covers all aspects of designing, drilling and completing a given oil and gas well. Large operators may refer to this as the 'pre-drill package' (purists may argue about the exact usage of terms but they both refer to the same thing). Smaller oil companies will simply refer to the documents as the well plan. This should be distinguished from the well profile, which only describes the proposed architecture and sizes of the well.

We have already seen how raw seismic information is processed into geological data. After poring over this data, bright spots and prospects are identified; however, a prospect must be converted into a well plan. Prospects are potential oil and gas reserves, destinations so to speak, and well plans are a means of reaching them[9].

Faster, Better, Cheaper

Picture this: six months before spudding a deepwater wildcat, the drilling team members are scratching their heads. Which rig will they contract? Will they keep the fragile balance between Pore Pressure Fracture Gradient (PPFG) and mud weight? Which drilling fluid will they use in high-pressure zones? Will they deliver a well that flows on time and within budget?

One way of managing budgets (as well as risk and uncertainty) is the Drilling Well Optimization Process (DWOP), also known as 'Drill the Well on Paper'. This refers to the process of analysing each step of the well construction process to generate ideas for improving performance and reducing cost. We will look at this concept in greater detail in due course. For now, it is important to define the technical limit for each activity or the minimum time required to complete each task in a perfect world. This will serve as a theoretical value only and can never be achieved as an actual target. Next, a realistic target based on the best past performance is established, which becomes the performance benchmark for the well[10].

Blueprint

Getting to the blueprint stage requires various scenarios to be enacted (DWOP) and huge volumes of information to be analysed and formatted. Well planning is a very broad concept that encompasses:

- The management of phased well construction service and supply processes to meet a desired timeline and objective
- Commercial aspects of contracts and pricing for well services and equipment
- Financial cover in terms of insurance and liabilities
- Legal conditions such as compliance with regulatory framework and outlining limits of responsibilities

> There can be as many a 100 different regulatory conditions and as many service and supply companies on a single well project.

• Design and operational aspects that cover detailed engineering drawings of well construction
• Health and safety considerations
• Environmental protection, and
• Political/cultural/linguistic aspects of the operations.

There can be as many as 100 different regulatory conditions and as many service and supply companies on a single well project. Subsequent issues will look in depth at regulatory issues such as permit to drill, supply and services procurement such as rig type, services contracts and well types. For now, we shall look at the main features of well planning and accompanying risk as well as the engineering aspect of a vertical exploratory well[11].

Essential Information

A well plan has essential information such as well number, location, block, partners, and level of confidentiality (confidential wells are called 'tight-holes'). It will include items such as the:

• Well objectives
• Surface location
• Longitude and latitude
• Eastings and Northings
• Water depths (in the case of offshore wells)
• Measured Depth (MD)
• True Vertical Depth (TVD)
• Azimuth
• Spud dates
• Critical dates such as first oil (which would really only be entered by a true optimist), and
• Seasonal or environmental factors that may affect operations.

The well plan also includes such things as:

• Rig details, rig preparations, transportation of the rig and setting it up
• Well control and contingencies
• Pressures (PPFG) and temperature (gradient)
• Directional targets and sidetracks
• Bottom Hole Assembly (BHAs) and hydraulics
• Casing depths and cementing details
• Contact list of key personnel, and
• Completions—how the final section of the well will be finished or completed.

Targets

Targets usually refer to geological targets, which are the depths of formations that likely contain oil and gas. They can also refer to pre-determined casing points. Depths are expressed as vertical and measured depths. TVD, for our purposes, refers to a depth taken from a ninety degree straight line from the surface down to the depth of interest. The measured depth is the actual distance drilled. Other formations or markers along with their age and lithology, i.e. sand/shale, will be noted. The TVD is measured from the top of the target to the bottom height of the reservoir. When you read that a reservoir had 78 feet (25 m) of 'pay' or

Figure 5 - View of Cuttings Analysis

oil-bearing sands that refers to the vertical thickness of the oil and gas reservoir. 'First oil' refers to the first time at which production of a certain reservoir occurs[12].

In the Dark

Reservoir information on exploratory drilling or wildcats will be limited if not unavailable. Although there may be some basic information on formation markers, porosity and permeability, temperatures, and the expected hydrocarbon gas or oil, much more information needs to be predicted such as the reservoir pressure, formation markers, the TVD to the tops of formations, and a range of other pressures. Only upon drilling will the true values be confirmed.

Regulatory Compliance

All regulations including health and safety considerations and environmental protection will be cited and acted upon.

Potential Hazards

Hazards are identified as geological/formation-related and environmental/operational. Exemplifying the former are shallow gas, shallow water flows, charged zones, depleted zones, overpressure, abnormal temperatures, the presence of H_2S or CO_2 and pressure faults. These will be covered in part by the well control plan which will have considered all aspects of well control and associated equipment. This includes:

- All wellhead components
- BOP stack and valves
- Accumulator
- Choke and kill lines
- Choke manifold
- Gas buster (or poor boy de-gasser)
- Drill string safety valves
- Standpipe manifold
- High pressure mud lines and systems (including cementing system)

• Drill strings
• Drill stem testing surface and subsurface equipment,
• Subsea well control equipment (if drilling from a floating vessel).

Operational hazards range from wellbore positioning (such as avoiding collision with existing wells or pipelines), avoiding shipping channels and avoiding cetaceans or other protected marine life. Operational risks include maintaining casing integrity, avoiding casing wear, maintaining wellbore stability and managing any pressure ramp near the Total Depth (TD).

Formation Evalution Plan

The Formation Evaluation Plan includes provisions for Logging-While-Drilling (LWD) or the electrical wireline logging program. This will outline the requirements for cutting samples, mud logging and formation evaluation logging. This allows the oil company to describe formations and understand actual drilling conditions which will vary from the seismic. Formation Pressure-While-Drilling (PWD) tools also exist. These can replace wireline or pipe-conveyed logging services and are made up as part of the BHA. This allows operators to measure formation pressure as it is encountered which improves well control, safety and drilling efficiency[13].

Potential hazards such as shallow gas flows or severe pressure changes can be noted earlier and preventative action taken which lowers risk and operational costs. Usually, these systems make use of binary coding using mud pulse telemetry where the surface operator and subsurface tools communicate by means of pressure pulses that are sent through the column of drilling mud. Mud pulse telemetry cannot be used while making a connection; this is one of its drawbacks.

Mud-Logging System

During drilling operations, a multitude of measurements are taken and monitored. Temperature, pressure, depth, torque and loading are just a few. Several systems exist on rigs to fulfill this function with mud-logging being a primary one.

The use of mud-logging systems was first introduced in the industry in the 1960s. Since then, advances in instrumentation and in the number of measured parameters have resulted in sophisticated mud-logging systems[14]. The advent of deepwater drilling also contributed to the progress of mud-logging techniques. Deep and ultra-deep water environments require very accurately controlled drilling operations. Any failure or negligence may cause human injury and economic losses. To control processes accurately, enhanced mud-logging is required.

Mud-logging systems encompass three different types of data. First, they collect and analyse drill cuttings (shale-shaker samples). Secondly, they measure and monitor the condition and content of the drilling fluid returns. Finally, they monitor and record mechanical parameters related to the drilling operation. All provide invaluable data as to whether the formations encountered bear oil and gas or how drilling is going[15].

Examining Cuttings

Drilling chips or returns, also known as 'cuttings', provide the operator with information as to whether hydrocarbons have been found by carefully examining cuttings brought up by the circulating mud. The mud logger or geologist samples cuttings from the flow equipment using a microscope or ultraviolet light to determine the presence of oil in the cuttings. Where gas reserves are concerned, they may use a gas-detection instrument. Often paleontologists examine drill cuttings under a microscope to detect and identify fossils that indicate the age of the formation and perhaps clues to its deposition[16].

During drilling, a mud logger will observe mud-logging parameters for any abnormalities. If an observed parameter presents unusual behavior, the mud logger immediately communicates this to the driller who will carry out certain procedures to solve the problem. Actually, the system allows the programming of alarms that will sound in the mud-logging cabin, alerting the mud-logger that the value of the observed parameter is outside the programmed range.

The number of observed parameters may vary according to a particular characteristic of the drilling operation, but the most commonly measured parameters are:

• Well depth (depth)
• TVD
• Bit depth
• Rate of Penetration (ROP)
• Hook height
• Weight on Hook (WOH)
• Weight on Bit (WOB)
• Vertical rig displacement (heave)
• Torque
• Drill string rotation per minute (rpm)
• Mud pit volume

> Formation core samples may be taken and these are the most important way of examining formations and any oil-bearing strata.

- Pump pressure
- Choke line pressure
- Pump strokes per minute (spm)
- Mud flow
- Total gas
- Gas concentration distribution
- H_2S concentration
- Mud weight in and out
- Drilling fluid resistivity
- Drilling fluid temperature
- Flow line
- Lag time, and
- Standard length[17].

Only some of the listed parameters are measured using sensor devices; some of them are estimated from measured parameters. The WOB, for instance, is an estimated parameter that is calculated using hook weight (a measured parameter) and the weight of the drill string elements (which allows for buoyancy in drilling mud and wellbore inclination).

Well Logging

Using a portable laboratory truck-mounted for land rigs, well loggers lower devices called logging tools into the well on electrical wire-line. The tools are lowered all the way to the bottom and then reeled slowly back up. As the tools come back up the hole, they are able to measure the properties of the formations they pass[18].

Electric logs measure and record natural (spontaneous potential) and induced (resistivity) electricity in formations. Some logs ping formations with acoustic energy and measure and record sound reactions. Radioactivity logs measure and record the effects of natural and induced radiation in the formations. These are only a few of the many types of logs available. Since all the logging tools make a record, which resembles a graph or an electrocardiogram, the records or logs can be studied and interpreted by an experienced geologist or engineer to indicate not only the existence of oil or gas, but also how much may be there. Computers have made the interpretation of logs much easier and logging tools using real-time transmission systems are now capable of imaging the wellbore as it is drilled[19].

Although, logging and measurement while drilling (LWD and MWD) tools have been available for many years, it is only recently that advances in data transmission and interpretation have progressed to generate accurate images of the wellbore. These images are based on real-time data and offer insight into what is really happening downhole.

Typically, a high-quality image is drawn from detailed, 3D resistivity data. This data is supplied by a resistivity tool similar to a logging formation micro-imager, which is run on wireline. This resistivity tool is capable of identifying wellbore features and characterising faults, cementation changes and threaded or spiraling caused by bit whirl. Software transforms the resistivity data into images of 3D wellbores that are viewable at all angles with simple mouse movements. The resistivity measurements are transformed into 360-degree azimuthal plots around the circumference of the wellbore to provide extremely detailed images[20].

The combination of resistivity and density services based on real-time logging images and geo-steering techniques enables operators to reduce risk and overcome geological uncertainties commonly associated with complex wells. Ultra high telemetry rates (12 bits per second) have been successfully used to optimise horizontal well placement as well as warn of wellbore stability issues before they become serious enough to jeopardise operations or impact drilling costs.

Wellbore stability problems are detected with ultrasonic callipers from density or sonic LWD tools. Hole enlargement or washouts can be identified while drilling or during subsequent trips. This is beneficial as it helps monitor wellbore stability and allows adjustments to be made to mud weights or effective circulating density as required. Wellbore stability problems are confirmed using vision technology incorporating Azimuthal Density/Neutron viewer software, which provides density image and calliper data while drilling. The software also generates 3D images and calliper logs. Together, these offer easier methods of understanding wellbore conditions during drilling operations. Additionally, the 3D density images and ultrasonic calliper allow wellbore instability mechanisms to be better characterised, and when necessary, resolved. This is particularly important in completions where gravel packs or expandable screens are required. The ultrasonic and density calliper information gathered during drilling can indicate whether hole quality is good enough to permit specialised completions to proceed. Up-logs obtained on a subsequent wiper trip allows visualisation of the hole enlargement and stress failures after drilling[21].

Specialised software uses a recorded mode to gather real-time dip information, provided by the LWD resistivity imaging tools. This information is harnessed to view geological structures and reduce the uncertainties in pre-existent geological models.

The software also allows structural dip picking from images, which can be used in combination with the real-time data for structural interpretation. Bed dips and layer thickness are also characterised, permitting the evaluation of structural cross-sections. The reduction in risk and geological uncertainty has made wellbore imaging hard to resist for production companies.

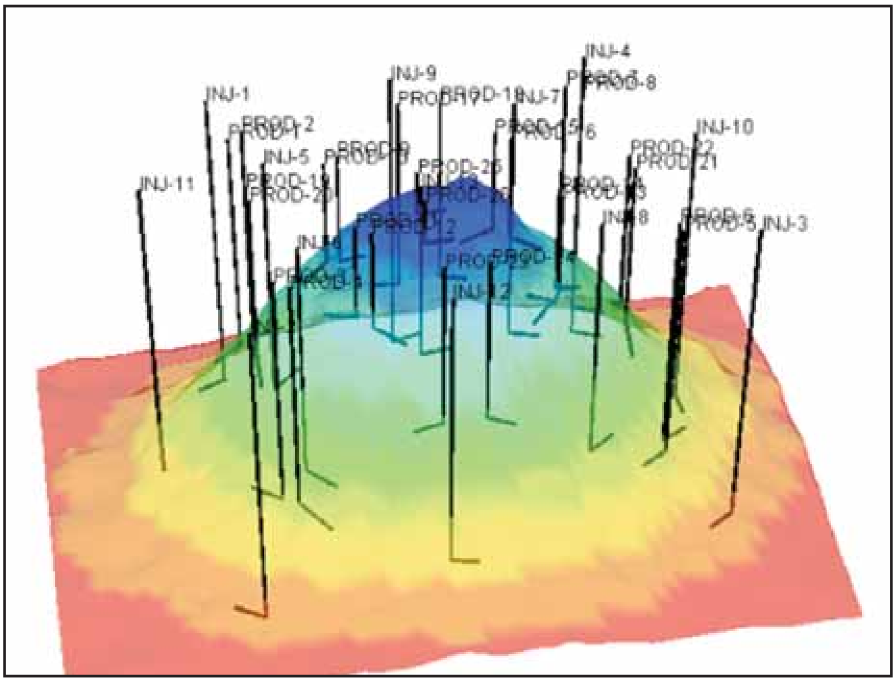


Figure 6 - Well Placement In Field Development

Pressure While Drilling

PWD tools are used to make accurate downhole measurements of:

- Equivalent Circulating Density (ECD)
- Kick detection, including shallow water flows
- Swab/surge pressure monitoring while tripping and reaming
- Hole cleaning
- Hydrostatic pressure and effective mud weight, and
- Accurate Leak-Off Test (LOT) and Formation Integrity Test (FIT) data.

Coring

Formation core samples may be taken and these are the most important way of examining formations and any oil-bearing strata. Cores are extracted by a 'core barrel' which usually takes 10 to 13 ft (3 to 4 m) lengths of

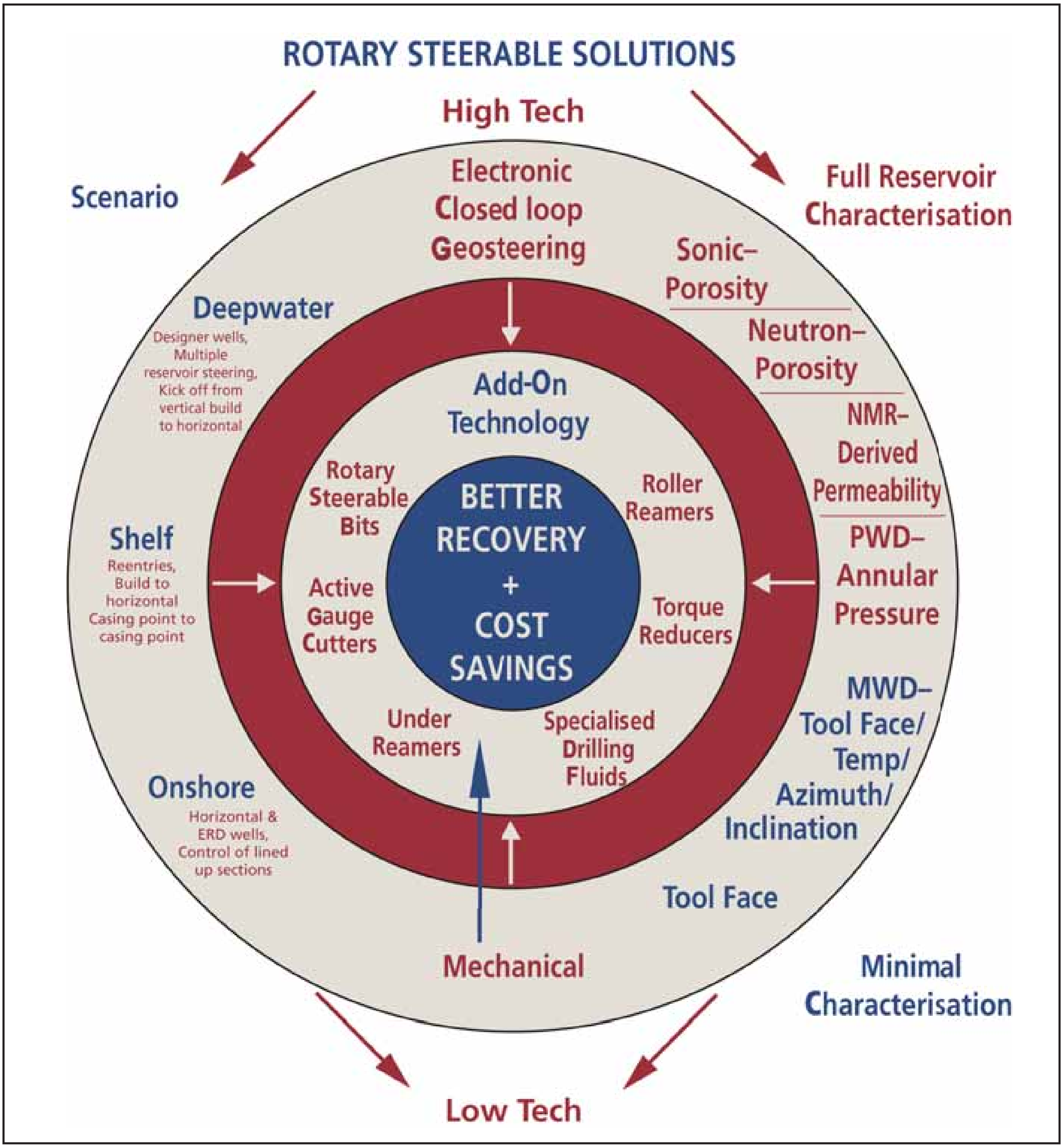


Figure 7 - Geo-Steering Technologies From High to Low Tech (EPRasheed)

the formation. As the core barrel is rotated, it cuts a cylindrical core a few inches in diameter that is received in a tube above the core-cutting bit. A complete round trip is required for each core taken. Much smaller and less representative cores may be extracted using a sidewall sampler in which a small explosive charge is fired to ram a small hollow cylindrical bullet into the formation. The bullets are tethered to strong retaining wires. When the tool is pulled out of the hole, the bullets containing the small core samples come out with the tool. Up to 72 of the small samples can be taken per trip at any desired depth. This provides positive real evidence of cross-flow, permeability and porosity. Laboratory tests are complex and can include fluorescence gas chromatography (TSF)[22].

Sampling and Screening of Cores

On board the ship, cores are physically described, logged and sampled. Three sections from the bottom half of each core are sampled for geochemical analysis. Deeper core sections are used in order to avoid contamination from modern petroleum pollution sources near the surface. Analysis of three sections per core increases the likelihood of encountering petroleum seepage, which is typically not distributed homogeneously throughout the sediments. All core material is frozen and stored until it is returned to the lab[23].

The objective of these analyses is to characterise the composition and origin of solvent-soluble hydrocarbons. The cores are stored in specially created conditions to preserve their characteristics.

Drilling to Total Depth

The final section of the well is what the operating company hopes will be a production hole. The formation of interest (the pay zone, the oil sand, or the formation- bearing hydrocarbons) will determine the answer to the make or break question: 'Is the well commercial, i.e. does it contain enough oil or gas to make it worthwhile to run the final production string of casing and complete the well?'

After the operating company has studied all the data from the various formation tests, a decision is made on whether to set production casing and complete the well or to plug and abandon it. If the hole is considered to be dry, that is not capable of producing oil or gas in commercial quantities, it will be plugged and abandoned. Sometimes, a dry hole may be sidetracked in an attempt to make contact with productive formations. This is usually the case if formation faulting is detected because a well drilled just a few feet on the wrong side of a fault can miss the pay zone altogether. It's a relatively simple task to drill a sidetrack, and certainly less costly than starting over.

At times, not enough oil or gas may be present to justify the expense of completing the well; therefore, several cement plugs will be set in the well to seal it off. As oil prices are cyclical, it is often the case that wells that were plugged and abandoned in the past may be re-opened to production if the price of oil or gas has become higher. The cost of plugging and abandoning a well is far lower than the cost of a production string of casing; therefore, the operator's decision is invariably oil or gas price driven[24].

Setting Production Casing

If the operating company decides to set casing, it will be brought to the well and for one final time, the casing and cementing crew will run and cement a string of casing. This casing is 'floated' into the hole to take advantage of its buoyancy and relieve the rig from holding the immense weight of several thousand feet of large diameter steel pipe. A 'float shoe' seals off the bottom of the casing and keeps drilling mud from flooding the casing as it is runs into the hole. Usually, the production casing is set and cemented through the pay zone; that is, the hole is drilled to a depth beyond the producing formation and the casing is set to a point near the bottom of the hole. As a result, the casing and cementing actually seal off the producing zone but only temporarily. After the production string is cemented, the drilling contractor's job is almost finished except for a few final touches.

Cementing

After the casing string is run, the next task is cementing the casing in place. An oilwell specialist cementing service company is usually called in for this job. Cementing is fundamental to the integrity of the well and considers factors such as annular volumes, formation-cement-wellbore interaction, slurry and set properties as well as cement sheath strength. Cement behaviour differs according to depth, pressure, temperature and loading conditions; however, this behaviour needs to be considered to ensure a good cement job.

Cementing applications include sealing the annulus after a casing string has been run, sealing a lost circulation zone, setting a plug in order to 'kick-off' a wellbore deviation or to plug and abandon a well.

> Once the major factors are characterised – bit walk tendencies, lithology, bedding and dip angles, BHA type, components, spacing and configuration – they can be collated to calculate the likely changes in wellbore curvature that the system can create.

Cementing involves pumping a cement slurry down the inside of the casing. When the slurry reaches the bottom, pump pressure is raised and this pops open a valve in the float shoe to allow the cement to be pumped out of the bottom of the casing, out the bottom end and back up the annulus. When the proper amount of cement volume has been pumped to seal off the casing and support it in the borehole, a plug is pumped to the bottom that wipes the wet cement off the inside of the casing and forces it all to the bottom, leaving the casing clean and ready for the next step in the completion process.

Perforating

Since the pay zone is sealed off by the production string and cementing process, perforations must be made in order for the oil or gas to flow into the wellbore. Perforations are simply holes that are made through the casing and cement and extend some distance into the formation. The most common method of perforating incorporates shaped-charge explosives, a principle that was developed during the war to penetrate tanks and other armoured vehicles. The shaped–charge, when fired, creates a high-velocity, ultra-high pressure plasma jet that penetrates the steel casing, the cement sheath and several feet out into the formation rock. Several perforating charges are arrayed in a radial pattern along the carrier gun. They are usually fired simultaneously, but may be fired sequentially for special applications using select-fire equipment.

Acidising

Carbonate reservoirs (See *Chapter 1: Origin of Oil*) often hold oil, but the oil may be unable to flow readily into the well because the carbonate formation has very low permeability. Rocks that dissolve upon contact with an acid, such as limestone or dolomite, are often 'acidised' to optimise production. Acidising is mostly performed by an acidising service company and can be done with or without a rig. It consists of pumping appropriately sized volumes of acid down the well where it travels down the tubing, enters the perforations, and contacts the formation. When the acid enters the formation, it etches channels that provide flow paths for the formation's oil or gas to enter the well through the perforations[25].

Fracturing

When rocks contain oil or gas in commercial quantities but the permeability is too low to permit good recovery, a process called fracturing may be used to increase permeability to a practical level. Basically, to fracture a formation, a fracturing service company pumps a specially blended fluid down the well and into the formation under great pressure. Pumping continues until formation integrity is overcome and literally cracks open. The fracturing fluid contains solid particles called 'proppant' (which can be plain sand or more-sophisticated material such as high-strength ceramic beads) suspended in a slurry, usually consisting of a polymer gel. When the formation fractures, the gel and proppant penetrate the fissure and travel out to the extreme end of the fracture. When pressure is relieved, the formation fracture tries to close, but is propped open by the proppant material. After the pressure is released, a de-viscosifier chemical called a 'breaker' is released into the gel to lower its viscosity and allow it to flow freely back into the well without disturbing the proppant or washing it back out of the fracture[26].

Case Study: Geo-Steering

In order to maximise drilling in the 'filet mignon' of the reservoir, geologists often require tight TVD corridors to be maintained or for several reservoirs to be drilled at a optimal inclination and azimuth. To achieve this, TVD and directional corrections can be made in either rotary or oriented mode. The limiting factors associated with oriented drilling led drilling engineers to seek rotary options[27]. Since the first use of the technology in the early nineties, rotary steerable systems have been proven as 'fit for purpose' and particularly well-suited to horizontal and multi-lateral drilling. Today, they are essential to geosteering as they almost universally deliver higher penetration rates, better hole quality and improved steerability[28].

Refining BHAs Through Offset Data

Thorough analysis of offset data enables BHAs to be refined and optimised. An extensive database allows previous BHA performance to be pinpointed and considered, thereby increasing the success of future BHAs. Once the major factors are characterised – bit walk tendencies, lithology, bedding and dip angles, BHA type, components, spacing and configuration – they can be collated to calculate the likely changes in wellbore curvature that the system can create. By extending the use of rotary steerable systems to field development programs or horizontal drilling campaigns, these benefits make very substantial cost savings[29].

Rotary Steerable Technology

Advances in rotary steering technology are bringing intelligent systems even closer. Although geosteering systems capable of finding and accessing reservoirs without human input are still some years away, several rotary steerables exist today. While high-tech electronic solutions are sophisticated by nature, these systems are especially suited to costly complex designer wells. A different approach is being adopted by a number of smaller service providers who are developing more cost-effective systems for the intermediate market. While most still rely on electronics, there are also simple systems reliant on mechanical devices. Simple or sophisticated, all systems can generate cost savings and improve recovery[30].

Less clear is whether criteria exist to make one system better than another. Perhaps a more objective approach is to determine the best fit by broadly matching rotary steerables with the varying dictates and expectations of deepwater, shelf or onshore drilling and completions.

Drawing these variables together, Figure 7 depicts deepwater, shelf and onshore sectors and its appropriately matched technology. Certainly, a rotary steerable system must help reach the reservoir and optimise the footage drilled within it, but beyond this there are many reservoir and well-dependent variables. The dogleg severity (the change in direction, measured in degrees per hundred feet, required to reach optimal reservoirs) performance of a rotary steerable system, for example, should be matched with the complexity and number of targets involved. In complex designer wells, sophisticated systems shine; in less complex horizontal wells, simple systems suffice. Similarly, costs also drive system choice. It is well known that the tight economics of onshore or shelf assets cannot withstand high rig rates, let alone expensive downhole equipment. Here, a match depends as much on reservoir placement needs* as it does cost. Consider deepwater versus onshore trip costs. In the former, an average round trip may cost US $500,000; the same trip onshore is hardly a tenth of this figure. In the first instance, it makes commercial sense to minimise trips; however, onshore it might make better commercial sense (depths and profile permitting) to induce trips by using conventional steering technology to line up sections and run in with rotary steerables where they have best effect[31].

Deepwater exploration frontiers are characterised by the highest rig rates in the industry and extreme exploration risk. This means contingency planning is a key component of deepwater operations. Relatively straightforward activities, such as logistics, can be rendered complex due to the remote and specialised nature of operations. Consequently, sophisticated rotary steerable systems that maximise efficiency and minimise risk are not only desirable, but necessary.

> In order to maximise drilling in the 'filet mignon' of the reservoir, geologists often require tight TVD corridors to be maintained or for several reservoirs to be drilled at a optimal inclination and azimuth.

In these deepwater instances, a full range of reservoir characterisation tools is also required. Sophisticated systems, coupled with full logging capability, reflect and meet deepwater frontier needs as offset data is often scarce and further asset development is dependent on data acquisition and interpretation. The general rule is the more data acquisition and characterisation the better. Data gathered while drilling supplements the pre-drill seismic package by increasing the footage drilled in optimal reservoir zones. A good rule-of-thumb is to consider the time-relevance of information; if the information is required to make critical decisions while drilling, real-time systems should be used[32].

Conversely, because mature assets usually are well-characterised and offset data is plentiful, the same degree of data acquisition may be unnecessary. This makes mature or onshore fields ideal candidates for simpler rotary steerable tools. As one moves down the characterisation list, there is a diminished need for complete characterisation. Intermediate or mature shelf assets may not require nuclear magnetic resonance or sonic logging, and in a marginal onshore context it is highly likely that a full LWD suite becomes redundant. Little more than toolface, azimuth, inclination, temperature and formation identification is required in this context. In exceptional onshore cases, the uncertainty associated with complex targets may require further logging, but often MWD plus a gamma system provides ample data. In this way, technology can be pared down to bare essentials and costs can be lowered. What may have once been considered a marginal or mature field can be revisited with new economic parameters and perhaps be revitalised.

Often, however, a serendipitous use of real-time data pays dividends. Recently, an operator drilling in the shallow shelf waters of offshore Texas, encountered two extremely abrasive formations. On an offset well, each consumed ten drill bits to get through the zones. The logging requirements were not particularly sophisticated, but the service company pointed out that if the sections were drilled using its rotary steerable system with ultra high-speed telemetry, it could measure and monitor drill bit vibration thought to be the cause of the rapid bit-wear. The operator accepted the recommendation and with real-time vibration monitoring, was able to detect and analyse the circumstances causing bit wear. By adjusting weight-on-bit, rpm and mud weight, the operator was able to minimise destructive vibration and drill both problem sections with a single bit each, saving more than US $2 million

> "By creating visualisation rooms in different operational sites and in other locations where engineers can 'see' reservoirs, oil companies can image 'harder to see' reservoirs such as thin layers which can be missed by conventional seismic."

from US $12 million Approval For Expenditure (AFE). The sophisticated solution costs more, but rig time was saved by eliminating eight bit change trips, and the added cost was more than compensated by the rig-time savings.

Add-On Technology

Representing opportunities for reducing casing wear, torque reducers can help overcome the concerns of the effects of increased rotation on tubulars. Also, roller reamers aid BHA stabilisation and reduce downhole vibrations. Under-reamers enable the diameter of production holes to be increased (especially important in deepwater scenarios where narrow pore pressure fracture gradients can jeopardise reservoir hole size) by allowing casing to be telescoped without sacrificing production. Specialised drilling fluids exist to reduce torque and improve rotary drilling efficiency[33].

Case Study: Expandable Tubulars

Although the reality of a downhole monobore (a single diameter casing string from well-head to reservoir-toe) is not in existence yet, half of the essential technology has been proven.

In the late 1990s, a relatively small group of engineers within Shell E & P, Halliburton and Baker Hughes laid out the plans for a technology that would have made Erle P Halliburton smile[34].

By forming technology ventures with Enventure (Halliburton) and E^2Tech (the precursor to today's independent expandable technologies from Baker Hughes), Shell gave the nascent expandable market the support it needed. Shell would later go on to sign deals with Weatherford allowing it to enter the expandable market.

In parallel to these deals, some service companies had already developed the expertise to expand slotted tubulars and were realising commercial downhole applications. Similar commercial applications for solid tubulars, however, have only become available in the past two or three years. Now, a broad range of operators have expanded solid tubulars to overcome well construction challenges such as preserving wellbore diameter, isolating lost circulation zones below the casing shoe and sealing-off swelling or poorly consolidated formations.

Today, there are three main open-hole applications for expanding solid tubular: slimming down well designs, contingency casing and repairs, handling lost circulation and bypassing trouble zones.

Slimming Down

In the deepwater arena, technology offers a real alternative to the seven or eight string casing configurations where 'telescoped casing' or 'borehole tapering' can severely restrict the production hole diameter in the geological objective. Another feature of the technology is that through 'localised' applications, repairs can be made to damaged or worn casing while patches or old casing strings can be replaced without the need for costly cutting and pulling casing. From an engineering perspective, wellbore stability and burst/collapse ratings of casing can be maintained in this way[35].

Contingency

Contingency systems can provide operators with an extra string of casing, which can be the decisive factor in terms of successfully drilling deepwater prospects. Increasing the section length of the casing without compromising casing diameter is especially useful in operations where large diameter top hole casing sections are otherwise technically or cost prohibitive. Consequently, it can be said that the technology gives the operator two casing strings for the price of one. The system enables operators to extend a conventional casing program for an exploratory well to reach promising zones that are deeper than anticipated.

Lost Circulation and Trouble Zones

For unexpected lost circulation or shallow-water flow zones in deepwater and sub-salt environments, the system provides affordable contingency solutions. In sub-salt environments, the system offers the most cost-effective solution for original casing that is stuck high or for reaching TD with larger production casing. Unexpected trouble zones are a common challenge in sub-salt or deepwater low-fracture-gra-dient environments. The open hole technology allows the operator to simply drill another hole section to bypass these zones. In older fields requiring redevelopment, the system can help reach deeper reserves and isolate water or gas zones that have penetrated horizontal re-entry wells. The well is drilled to the target reservoir, casing is run, cemented and expanded.

This technology holds much promise for deepwater fields where deep targets below the mudline may not be accessed economically with conventional technology.

Before the economies of scale regarding standardised casing design and supply materials, however, there are still further operational and design challenges that must be overcome. These challenges are the delivery of so called 'gun barrel' under-reamed gauge holes, increasing the expansion ratios of under-reamers to above 25% of pass through or body size, callipering, cementing type and method, maintaining a consistent internal diameter of casing which has been expanded at connections, and reducing the risk of swab/surge dependent on the expansion method. Here rotary expansion may have some advantages as the application of torque and weight is used to expand the casing as opposed to weight/force applied axially. At any rate, top down expansion is always preferable because if the expansion mechanism fails then any subsequent fishing can be achieved more easily. In the opposite, it is harder to fish a larger diameter component into or within a smaller diameter as would be the case of bottom up expansion.

Case Study: Digitalisation

Imagine producing a commodity but not knowing how much you have to begin with or have left. This kind of blind production is likely to be a relic as digitalisation promises to offer oil companies the ability to see production in the form of subterranean migration of hydrocarbons as they are produced over the lifecycle of the asset. As well as radically changing production, it promises to do the same with drilling completions through remote-controlled centres[36].

Combined with 3D seismic, e-drilling will provide the technology to realise real time modelling, supervision, optimisation, diagnostics, visualisation, and control of the drilling process from a remote drilling expert centre. This system will enable decision makers to have better insight into the status of the well, and formation surrounding the well, and thus make better and quicker decisions. This is of particular importance when problems or unusual situations arise and experts are called in to make decisions. They will quickly be able to grasp the situation and make the correct decision.

As compared to classical integrated reservoir engineering studies, an event solution study typically includes seismic and geology characterisation, reservoir simulation, history matching, field development, facilities and economics. Performed in two to three months, the event solution is characterised by a myriad of multiple parallel workflows and processes to assemble a rapid and integrated reservoir understanding towards the study objective, which includes uncertainty analysis and risk assessment to focus on what really matters. A team of 20 to 30 experts collectively work during the project's duration, providing synergy of mind and direction to reach the study objective and maintain consistency in each study discipline.

> "By regulating the flow and pressure of several reservoirs, a balance can be achieved to ensure reservoirs behave according to what is best in light of the big picture."

By combining real-time drilling analysis with 3D visualisation, the system allows all involved personnel a common working tool. It also provides the user with access to historical data (playback scenarios) for experience exchange and training. The overall result is a more cost-effective and safer drilling and well construction operation.

Seismic multi-component 3D and 4D technologies, along with better seismic imaging, help drill more productive wells because they provide greater precision of the location and migration of hydrocarbons. Multi-component involves larger volumes of data and enables the direct detection of hydrocarbons as well as reservoir geometries.

Vertical Seismic Profiling (VSP) aids exploratory and development drilling by reducing risk and uncertainty. In this way, seismic has evolved from being an exploratory risk mitigating tool to a reservoir management tool with applications in mature fields.

Recently, companies have successfully implemented seabed permanent seismic arrays which take a lifecycle approach and include taking repeat shots, overlaps and using permanent cables that use fibre optics.

By creating visualisation rooms in different operational sites and in other locations where engineers can 'see' reservoirs, oil companies can image 'harder to see' reservoirs such as thin layers which can be missed by conventional seismic. Visualisation serves as the 'common language' that enables geophysicists, geologists, engineers and asset managers to work effectively toward a common goal. With 4D time-based seismic, it is also possible to view migration as two time-lagged surveys, say a year apart, which will show how hydrocarbons have moved. This has tremendous value in understanding reservoir fluid paths and behaviour which ultimately means more oil.

Using satellites and fibre optic cables to communicate with multiple pay zones, the industry has set its sights on truly intelligent completions and has commercialised the downhole tools required to harmonise production.

In the old days, the equation was pretty simple: one reservoir meant one completion which meant one well. This changed, however, with the advent of dual completions, which allowed a single wellbore to receive production from two reservoirs. Although dual completions could reduce well numbers by half, reserves were not exploited effectively and well numbers remained unnecessarily high. Combining completions to co-mingle production from multiple pay zones reduced well numbers and costs, but two drawbacks emerged. First, well intervention was required more often than not. Second, heterogeneous reservoirs were treated as if they were identical.

The ideal approach is to treat pay zones individually as this makes for a much deeper understanding of reservoir characteristics. Consequently, this leads to better reservoir management, which in turn means higher levels of production over a longer life span. This was the overwhelming logic behind single and dual completions. Large numbers of wells, however, do not make the best use of resources.

Although reservoirs are complicated, intelligent completions are simple. Essentially, they take a big-picture view and aim to cost-effectively manage heterogeneous pay zones. Production from interrelated or layered reservoirs must be continually regulated and co-mingled and real-time data must be provided to make the best management decisions regarding the use of a network of downhole chokes, gauges and fibre optics to regulate production.

It is widely recognised that depleting one reservoir affects another nearby. By regulating the flow and pressure of several reservoirs, a balance can be achieved to ensure reservoirs behave according to what is best in light of the big picture. Zonal isolation is a good example of how intelligent completions can help predict, isolate and balance water and gas influxes in different locations according to long-term needs. Another benefit is that gas and water can be injected into multilateral or multilayer reservoir zones with a better understanding of how this will affect production from interconnected reservoirs.

By manipulating a downhole network of chokes and gauges, a production engineer seated hundreds of miles away can manage the production of several reservoirs, wells and fields. In this way safety is improved, costs are cut, and more reserves are accessed.

Broadly speaking, high-cost developments such as subsea installations with high intervention costs are particularly well-suited to intelligent completion. Their greater depths and complex well trajectories also make them ideal candidates. Two other areas suited to intelligent completion are selective production of multiple reservoirs and the optimisation of artificial lift operations.

With intelligent completion still in its infancy, financial costs are high and investment can be justified only on high-return projects. Technical restrictions also exist. Usage is limited to wellbore diameters of seven inches or larger, with high flow rates typically 6,000 bbl or greater. Downhole temperatures cannot exceed 120ºC (247ºF).

Despite these limitations and relatively few worldwide installations, major oil companies are devoting more resources to completing wells intelligently.

Truly intelligent completion systems are, however, not in the immediate future. Perhaps a more accurate description of today's technology would be remote control completions, as completions are not yet closed-loop. In other words, they are not autonomous, self-controlling systems and human input is still required. With technology moving at an inexorable pace, closed-loop completions will still be a goal for the long term.

Representing unquestionably better production, automation is an irreversible process. Each downhole sensor that sends real-time data makes us more conscious of its value. As more equipment is integrated within the intelligent completion, it becomes more difficult to view reservoirs separately. Automation offers an unprecedented flexibility in terms of asset and production management strategy. As commodity prices fluctuate, production from a given field can be halted or accelerated to mirror market conditions.

We have seen how complex the well construction process is and how imaginative well profiles such as Pregnant Ladies and Fishbones help strike oil and maximise its production. We have seen that the ultimate decision to complete or plug and abandon a well is dependent on the oil price. As oil reserves become scarcer, *Chapter 8: Extreme E & P* considers the most daring of wells that are drilled in the deepest waters, Arctic conditions and deepest reservoirs. What was once thought unthinkable has now become part of our oil and gas reality.

References

1. My first encounter with the 'Pregnant Lady' well profile was with Shell to avoid drilling a highly unstable zone while numerous 'Fishbones' were found in Saudi Aramco. Fishbones are also known as multi-laterals.

2. Seismic Inversion by Mrinal K. Sen, ISBN: 978-1-55563-110-9 Society of Petroleum Engineers.

3. Principles of Petroleum Development Geology by Robert Laudon, ISBN: 0-13-649468-4, Prentice Hall.

4. Seismic reduces but does not eliminate the risk of dry-hole. Dr Drill always has final say.

5. Actual requirements will vary from country to

country depending on the environmental or marine authority.

6. The cost increases due to time involved but much higher quality data is acquired.

7. Again seismic will reduce risk but may miss features. Drilling is required to be certain.

8. Originally from 'Well Planned' by Wajid Rasheed Brazil Oil and Gas Issue 4 2005.

9. Theoretical means of course, the well needs to be constructed.

10. This is set by all members of the team.

11. Vertical wells may require a means of directional control due to formation trends or other drilling problems.

12. First oil is notoriously difficult to predict.

13. Abnormal Pressures While Drilling—Origins, Prediction, Detection, Evaluation. Jean-Paul Mouchet and Alan Mitchell, ISBN: 9782710809074 Editions TECHNIP

14. Mud Logging J C Placido et al Brazil Oil and Gas Issue 4.

15. Idem.

16. Pollen and spores are also examined especially as fossils will have been broken up by the drilling process.

17. Many other parameters exist and are dependent on operational need.

18. Certain wireline logging applications have been superseded by LWD.

19. Harts E & P Dec 2003 Drilling Column. This article was written jointly with the late Chris Lenamond 'Downhole Vision'.

20. Idem.

21. Idem.

22. Obviously the problem lies in the time delay between cores being acquired and analyzed.

23. Theoretically cores should be frozen. Although desirable, this is not always possible, especially in desert areas.

24. As with all things in the industry which are oil price driven.

25. Applied Drilling Engineering, Textbook Vol. 2 A.T. Bourgoyne Jr., K.K. Millheim, M.E. Chenever, ISBN: 978-1-55563-001-0.

26. Idem.

27. Society of Petroleum Engineers/Canadian Institute of Mining. Wajid Rasheed Paper 65504 Controlling Inclination in Tight TVD Corridors. Presented at the International Conference on Horizontal Technology, Calgary, Canada, Nov 2001.

28. 'Drilling', American Association of Drilling Engineers, Official publication. Sep 02 'Power steering'. Discusses the Rotary Steerable market.

29. Idem.

30. Well documented across the industry.

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33. Applied Drilling Engineering, Textbook Vol. 2 A.T. Bourgoyne Jr., K.K. Millheim, M.E. Chenever, ISBN: 978-1-55563-001-0.

34. Harts E & P Oct 2004 Drilling Column. Expand your mind.

35. Keynote Address, Society of Petroleum Engineers Annual Technical Conference, Houston, USA. 2004 by Wajid Rasheed 'Reaching the potential of the Monobore: Intelligent tubulars, drill-pipe and underreamers.

36. Harts E & P 2002 Wajid Rasheed 'Intelligent wells linked by satellite'.