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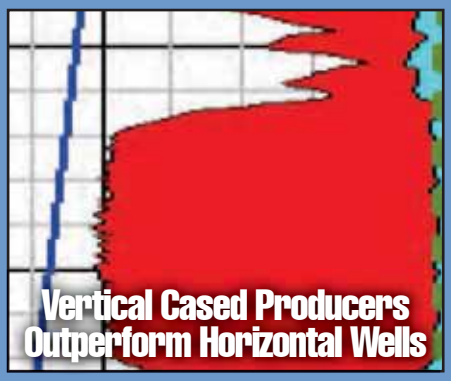


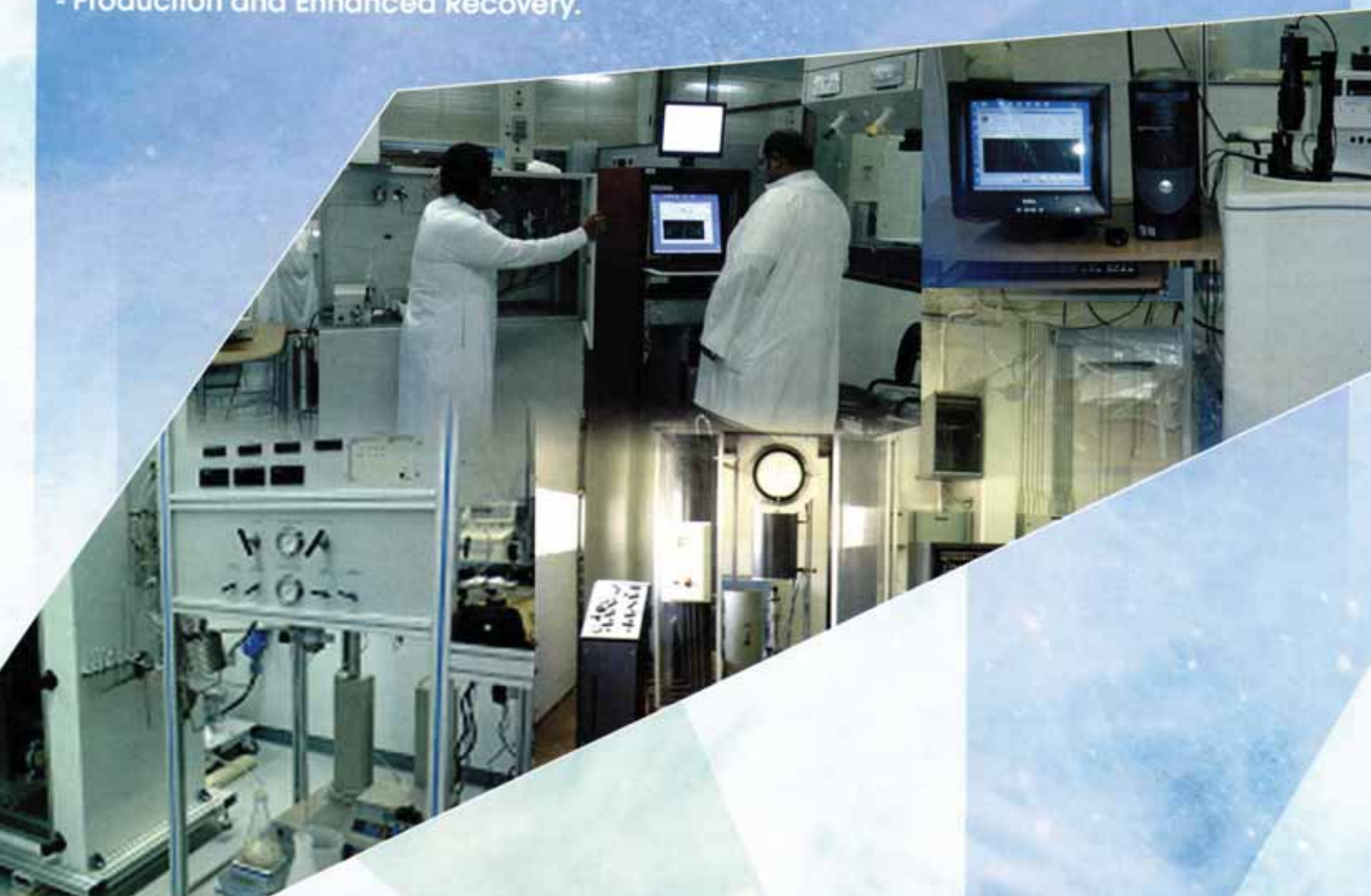
Vertical Cased Producers Outperform Horizontal Wells

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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EPRASHEED signature series
2013 – Issue 35
Saudi Arabia oil & gas
Saudi Arabia Oil & Gas (Print) ISSN 2045-6670
www.saudiarabiaoilandgas.com
Saudi Arabia Oil & Gas (Online) ISSN 2045-6689

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Energy Breakthroughs Showcased

DUBAI, U.A.E., 7 November 2013 The Middle East is home to the largest digital oil and gas fields in the world, and so Dubai proved to be a fitting location for the Society of Petroleum Engineers Intelligent Energy Conference on Oct. 28-30.

Sponsored by Saudi Aramco, the three-day event attracted more than 18,000 participants and visitors and allowed company engineers and scientists to showcase Saudi Aramco's ground-breaking upstream technology.

The conference is the world's premier knowledge- and experience-sharing forum for intelligent energy development and implementation across the exploration and production value chain.

Under the theme "Realizing the Full Asset Value," the conference was opened by conference executive chairman and Saudi Aramco chief petroleum engineer Ali Alghamdi, along with the deputy head of the Supreme Council for Energy in Dubai, Saeed Mohammed Al Tayer, managing director and CEO of Dubai Electricity and Water Authority.

"We envision this event to provide a rich platform for unlocking the potential of the digital field and paving the way toward greater value creation," said Alghamdi in his opening remarks. "This comes at a time when the industry is facing new unique challenges, including challenging plays, expanding geographic locations, and increasing demand for energy. In turn, our industry, through innovation and technology, has been able to tap into resources that were not reachable in the past. Such technologies include extended and multi-lateral drilling, geosteering, remote control and monitoring, and integrated collaborative environments."

Alghamdi told the audience that intelligent energy was helping the industry overcome the scarcity of skilled

> Young engineers now have access to the expertise of seasoned professionals who might be in different locations, or even different companies, through real-time collaborative environments.

manpower resources. "Through the use of automated processes, collaboration centers, and digital field implementation, engineers are able to spend more time to gain insight and make effective decisions, while spending less time trying to gather and manage data. Young engineers now have access to the expertise of seasoned professionals who might be in different locations, or even different companies, through real-time collaborative environments," he said.

During the conference more than 100 technical presentations were delivered by a wide range of distinguished speakers representing more than 50 companies.

Hussein Al-Qahtani, manager of Process and Control Systems at Saudi Aramco, told attendees that the company has been able to expand from not only an oil and gas company but to one that operates in the wider energy sector, including chemicals and electric power.

He also added that one of the most important elements of research for the company was smart engineering — a more sophisticated and intelligent approach to data analysis to help exploration and recovery efforts.

Saudi Aramco has already taken steps in this direction with its new Engineering Solutions Center, which provides a collaborative integrated information environment for multi-disciplinary engineering teams to work together more effectively than ever before. The center has launched a new era of integrated solutions, allowing immediate data flow from operating facilities to engineers and scientists using the latest imaging techniques.

Evidence of Saudi Aramco's leadership in intelligent field technology can be seen in the more than 15 working papers authored and presented by experts from various organizations.

Second Honor in a Month for Energy Management

DUBAI, U.A.E., 14 November 2013

Saudi Aramco continues making strides toward achieving its strategic goal: to maximize the Kingdom's energy resources.

Only a month after winning the Association of Energy Engineers (AEE) Award at the International Conference for Energy Engineering in Washington for its ongoing efforts to reduce energy consumption, the company added a new achievement by winning the Gold Special Recognition Award at the Emirates Energy Awards on Oct. 27.

This event was held under the auspices of HH Sheikh Mohammed ibn Rashid Al-Maktoum, UAE vice president, president of the Council of Ministers and ruler of Dubai.

Ahmad Al-Sa'adi, vice president for Gas Operations, received the award on behalf of Saudi Aramco from HH Ahmad ibn Sa'eed Al-Maktoum, honorary president of the Emirates Energy Award. Saudi Aramco earned this award for its efforts and achievements with regards to energy management, which includes large energy projects, small energy projects, research and development, innovation and energy efficiency.

Al-Sa'adi said that Saudi Aramco's experience with energy efficiency is nothing new as the company has been proactive in the field for about two decades, as evidenced by the many initiatives and achievements, including this one, over the years.

He added that this award is proof that the company is heading on the right track and that "even though we received this award for our efforts in energy efficiency for the company's operations, we look at it in the context of our leadership in this field on the Kingdom level. The Saudi Aramco Energy Management Team works as part of the Saudi Energy Efficiency Center Team, which

> As pioneers in energy efficiency, and since our efforts and initiatives in this field are steadily progressing toward making us a world leader, we look forward to the future and to support whatever projects and initiatives promote energy efficiency.

is supervised by the Ministry of Petroleum and Mineral Resources, to put in place a comprehensive national energy efficiency program and the plans needed for the program to succeed.

"The Accelerated Transformation Program (ATP) has put in place a comprehensive strategy for energy efficiency through the Saudi Energy Efficiency Center. The strategy includes a number of goals, such as increasing the level of power consumption saving from 25 percent to 45 percent, which is currently underway," he said.

"As pioneers in energy efficiency, and since our efforts and initiatives in this field are steadily progressing toward making us a world leader, we look forward to the future and to support whatever projects and initiatives promote energy efficiency," added Al-Sa'adi. "Awards are one way of recognizing the efforts of energy efficiency advocates. We also continue to focus on efforts that highlight perfect cases that achieve the ultimate goal of conserving energy."

The Emirates Energy Awards are designed to spread awareness on the importance of striving for sustainable growth, not only in the UAE but in the Middle East-Northern Africa region as a whole.

The awards recognize best practices in energy conservation. These practices should be innovative, cost-effective and leave a positive impact on the region in a manner that increases the awareness of the importance of energy conservation for society as a whole.

SATORP Progress Marches On

JUBAIL, 21-November 2013

Executives from Saudi Aramco, Total, and their joint venture, Saudi Aramco Total Refining and Petrochemical Co. (SATORP) met this week to see the latest progress on the SATORP conversion refinery in Jubail.

The meeting and site visit was a follow-up of an earlier gathering of CEOs in April, and it provided a chance for Saudi Aramco president and CEO Khalid A. Al-Falih, Total chairman Christophe de Margerie and SATORP CEO Fawwaz I. Nawwab to mark the latest steps in the refinery's construction. The visit also allowed the company executives a chance to examine plans for the refinery's scheduled full startup.

"This visit marks an important milestone for SATORP, and for the partnership between Saudi Aramco and Total," said Nawwab. "By now, construction is nearly complete, and many of our units at SATORP Refinery are already producing products for local and international markets. As we move toward our final startup in the next few months, we are ensuring that SATORP delivers on its commitments to provide reliable petrochemical and fuel products to our customers, as well as a new catalyst for economic growth in the Kingdom."

With the creation of SATORP, two oil industry giants – Saudi Aramco and Total – have agreed to combine their strengths at a crucial time in the global economy, as the world's demand for energy and for petrochemical products continues to increase. Initially signed in 2006, with construction commencing in 2010, SATORP has become a key driver for industrial development and growth in Jubail and a magnet for local and foreign investment.

SATORP refinery will produce ultra-low sulphur refined products including gasoline, kerosene, and diesel complemented with different quantities of petrochemical products such as benzene, paraxylene and propylene to enhance the economic return of the complex. Petroleum coke is another product that will be produced in the Kingdom for the first time.

Joint ventures such as SATORP are not only incubators for Saudi-owned small- and medium-size manufacturers and service providers. They fit into Saudi Aramco's commitment to foster a knowledge-based economy in which thousands of well-paid Saudi

> As we move toward our final startup in the next few months, we are ensuring that SATORP delivers on its commitments to provide reliable petrochemical and fuel products to our customers, as well as a new catalyst for economic growth in the Kingdom.

technicians, engineers and operators can find exciting job opportunities. Current employment at SATORP has reached 1,262, including secondees from Saudi Aramco and Total.

As of October 31, 99.4 percent of the overall project had reached completion. Currently, 90.9 percent of refinery units have been handed over to operation. The overall project cost is expected to be under budget.

With several units already in full operation, SATORP is already marking its presence on the global markets. The first production of hydrogen commenced in March. The first crude unit was handed over to operation in April. And as of September, SATORP successfully and safely launched its first shipment of 80 tons of fuel oil at King Fahad Industrial Port (KFIP), where Saudi Aramco lifted this shipment. Shipments of various products have followed.

AOC Sponsors Leading Chemical Engineering Awards

UNITED KINGDOM, 28 November 2013

Aramco Overseas Company (AOC) was chief sponsor of November's prestigious IChemE Awards 2013 held in the UK, which recognize innovation and excellence in the field of chemical engineering.

Founded in 1922, IChemE (Institute of Chemical Engineers) has a global professional membership within the industry and boasts close to 38,000 members across 120 countries.

Affiliate AOC, headquartered in Europe, took this opportunity to give greater exposure to Saudi Aramco among the leading specialists and academics in attendance. Networking in such technical fields will allow the business, through AOC, to foster new relationships.

Delivering the evening's key note address, Nabil Aldabal, Managing Director of AOC emphasized the importance of awards ceremonies like these, which reward cutting-edge thinking. "Nights like this highlight the continuing technological advances in an industry which is of fundamental value to the global economy. Furthermore, we believe these achievements can help meet the challenges that come with an ever-changing energy landscape.

"Since 2012, Aramco has continued to expand its refining capacity and integration of new chemicals facilities, which means more of what we produce will contribute benefits further down the value chain," he told the audience, which included leading executives from a host of industries including oil and gas, chemicals and pharmaceutical.

> Since 2012, Aramco has continued to expand its refining capacity and integration of new chemicals facilities, which means more of what we produce will contribute benefits further down the value chain

Indeed, movement down the value chain, through potential projects in conjunction with IChemE members, can assist the Aramco business to further its downstream activity, in products such as aromatics and polymers.

AOC was also sponsor of one of the ceremony's key accolades, the Water Management and Supply Award, an area which holds particular resonance with Saudi Aramco, as it looks to improve efficiencies in processes that require heavy water usage. The winners of the award were South Africa's Trailblazer Technologies for their solutions related to acid rock drainage (ARD), an issue that affects the fossil fuel industry.

The ceremony, this year held near Manchester (UK), is the institute's global edition and entries from all over the world were in contention. Dr. David Brown, IChemE's chief executive congratulated all of those shortlisted for this year's awards, especially the winners. "To have winners from five different continents shows the truly global nature of the IChemE Awards as they continue to grow from strength to strength."

This year's proceedings featured a record number of entries from countries including Germany, Japan, Singapore, South Africa, Switzerland, the Netherlands, the UK and the United States.

"The IChemE Awards represent the hard work, inventiveness and achievements of thousands of chemical engineers across the world, and we are proud to host them on behalf of the profession," Dr. Brown added.

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Vertical Cased Producers Outperform Horizontal Wells in a Complex Naturally Fractured Low Permeability Reservoir

By Danang R. Widjaja, Stig Lyngra, Dr. Fahad A. Al-Ajmi, Uthman F. Al-Otaibi and Dr. Ahmed H. Alhuthali.

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Abstract

This article is a case study for a complex highly fractured low matrix permeability reservoir. The material presented demon- strates that understanding the fracture influence on reservoir fluid flow is essential for successful development and reservoir management of this type of naturally fractured reservoir. Sev- eral well examples are offered illustrating the paramount im- portance of the completion strategy to the enhancement of matrix oil recovery and minimization of natural fracture net- work water production with increased reservoir maturity.

The case study reservoir was initially developed with a small number of vertical cased, perforated and stimulated wells pro- duced at a restricted total off-take rate and pressure, and sup- ported by peripheral water injection. The next development phase was the drilling of single lateral horizontal producers, completed open hole with approximately 1 km of reservoir contact. In the earlier stages of production, both vertical and horizontal well completion types performed well as the natural fractures were oil filled.

As water moved towards a structurally higher position due to natural fracture system depletion, the open hole completions became a major water production source. Subsequently, a revi- sion of the well completion strategy was required to minimize the water encroachment through the fracture system so as to maximize matrix oil recovery and also resolve well lifting problems. This article presents the production performance review that followed the recompletions of the existing open horizontal wells with perforated liners or special equipment, such as stage stimulation completions.

The production performance data of the recompleted hori- zontal wells are compared to the production performance of the original wells and with newly drilled cased, perforated and stimulated vertical producers. In this case, it is apparent that simplicity wins, and the vertical well solution is the optimum well strategy for future development.

Introduction

This case study deals with a giant mature field located in the Eastern Province of the Kingdom of Saudi Arabia. The field was discovered in the early 1940s[1]. Since the mid-1950s, peripheral water injection has been the main pressure support mechanism[2].

The field production is primarily from two fractured carbonate reservoirs. The Upper reservoir is prolific with excellent reservoir properties throughout the whole field[3]. The Lower reservoir has a much lower matrix permeability of 1-2 millidarcies (mD)[4] and is hydrocarbon bearing only in the southern part of the field[5]. The well productivity and reservoir fluid flow in the Lower reservoir is mainly controlled by the fracture system[4]. Moreover, the pressure data from the two reservoirs during the life of the field demonstrate pressure communication[6, 7]. As a result of prudent reservoir management practices during the more than

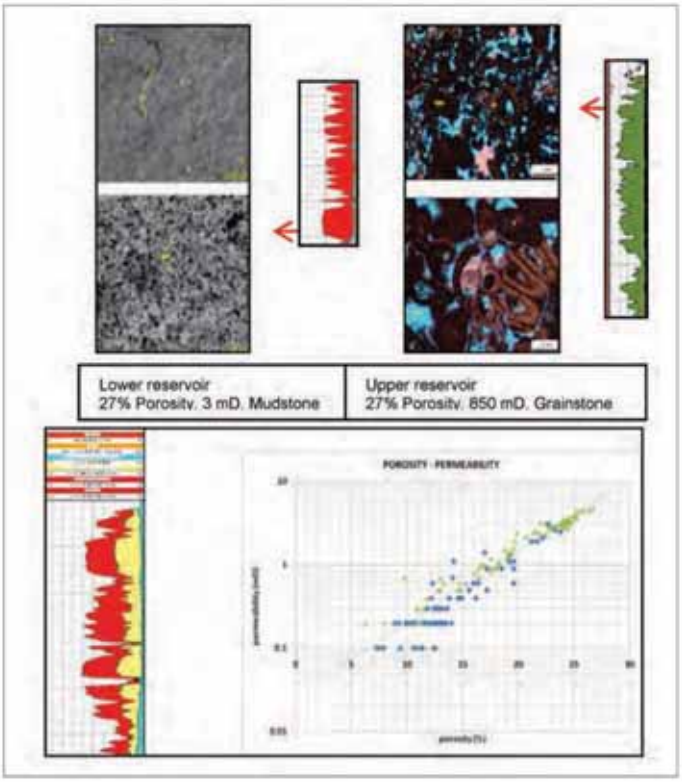

Fig. 1. Well log, core porosity-permeability plot and scanning electron microscopy photos.

Fig. 2. Small scale (left) and large scale (right) fractures[4].

60 years of production, the field is still delivering a substantial oil production rate, and the water cut is still moderate (~35%)[4].

This article is focused on the performance of different types of wells completed in the Lower reservoir.

Lower Reservoir: History, Geology and Reservoir Properties

The Lower reservoir hydrocarbon discovery was made in early 1949 when one of the first southern area Upper reservoir wells was deepened into the Lower reservoir. The discovery well was located close to the structural crest of both reservoirs. In 1954, another Upper reservoir well was deepened and put onstream as the first Lower reservoir producer.

The reservoir was deposited as an isolated buildup within the Arabian intrashelf basin and is approximately 300 ft thick. It contains primarily very fine grain mudstone with good porosity and low permeability. Porosity can be as high as 27%; however, matrix permeability rarely exceeds 2 mD[4]. Extensive log and core data indicate that the reservoir consists of several zones with tight deposits between the lobes. Figure 1 displays a typical well log, core porosity-permeability cross plot and scanning electron microscopy (SEM) photos. In Fig. 1, the SEM photos compare Lower reservoir mudstone and Upper reservoir grainstone of analogous porosity (27%), but with entirely different matrix permeability, 3 mD and 850 mD, respectively.

Image logs indicate that the Lower reservoir is heavily

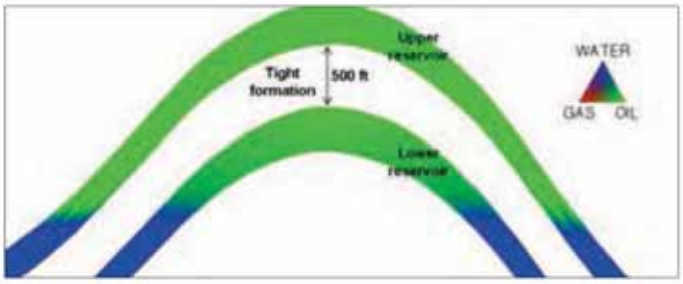

Fig. 3. Schematic cross section: Upper and Lower reservoirs.

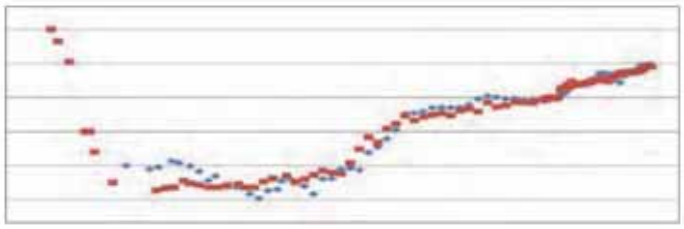

Fig. 4. Average reservoir pressure history for Upper (red symbols) and Lower (blue symbols) reservoirs.

fractured. These fractures, ranging in size from large-scale fractures/fracture swarms to small-scale fractures/diffuse fractures, play major roles in well productivity, reservoir fluid flow and recovery efficiency. As illustrated in Fig. 2, the large fractures can often cross several reservoirs and can extend for hundreds of meters. This type of major event has been identified as the cause for communication between Upper and Lower reservoirs.

A detailed understanding of the fracture system has become essential for Lower reservoir development planning due to the occurrence of unexpected major water-bearing fractures during drilling of new producers. Several fractures and fault interpre- tation models for this field have been presented in the past[8, 9], revealing a dominant east-northeast fracture trend. The current fracture characterization was based on 8,000 ft of core, 19,000 ft of image logs, horizontal well saturation anomalies, high flow production log responses, mini-drill stem test (DST) formation tester observations4 and pressure transient data[3]. All this information was applied in conditioning a predictive fracture model[7].

The fracture predictions away from well control are merely probabilistic realizations, primarily founded on the well data conditioning. The only available data that currently can be used for quantification of the fracture parameters and validation of fracture events in the inter-well areas are pressure transient derivative responses[3]. The pressure transient interpretations provide input on a well's distance to major fracture events and fracture conductivity. Moreover, fracture exclusion areas were established, precluding major fractures within the drainage areas for the wells in which homogeneous pressure derivative responses were observed.

Inter-Reservoir Communication Between the Upper and Lower Reservoirs

The Upper and Lower reservoirs are separated by approximately 500 ft of non-reservoir limestone, Fig. 3. Figure 4 presents the pressure data during the life of the field for both reservoirs, corrected to a common datum. Even though production from the Lower reservoir started later, the reservoir pressure at the start of production was found to be the same as the Upper reservoir pressure[6, 7]. This indicates that the Lower reservoir had experienced the same pressure depletion as that of the Upper reservoir, despite the fact that no production took place in the Lower reservoir.

Pressure transient analysis (PTA) studies have confirmed the presence of highly conductive features linking the Upper and Lower reservoirs in the southern part of the field[3, 10]. Moreover, relevant data from other sources,

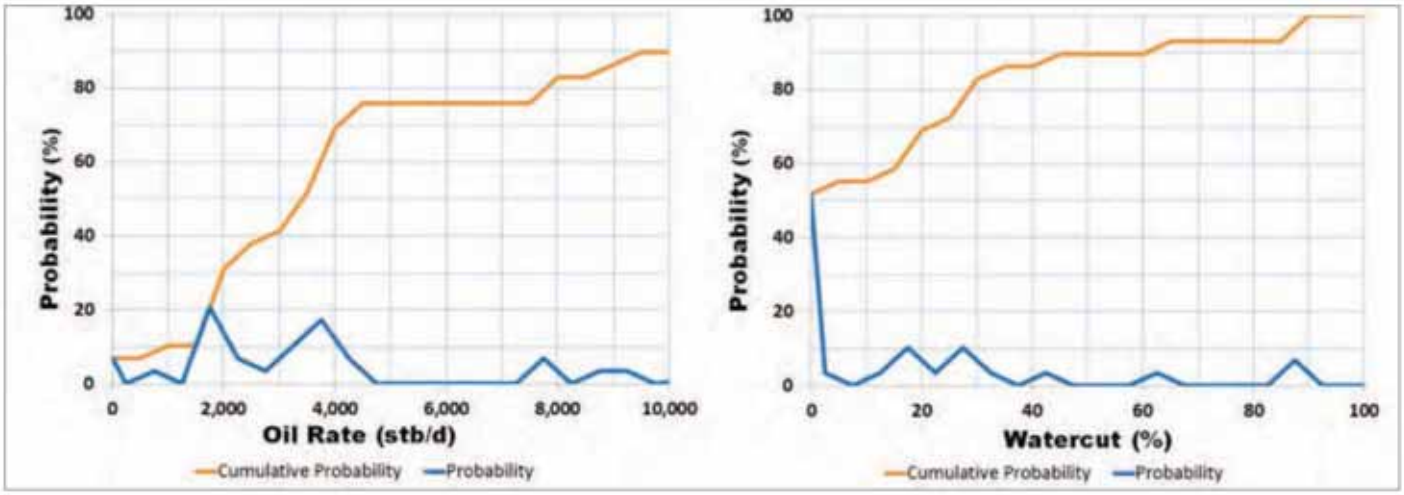

Fig. 5. First year oil production rate and water cut results distributions for all vertical/deviated wells put onstream 1954-2012.

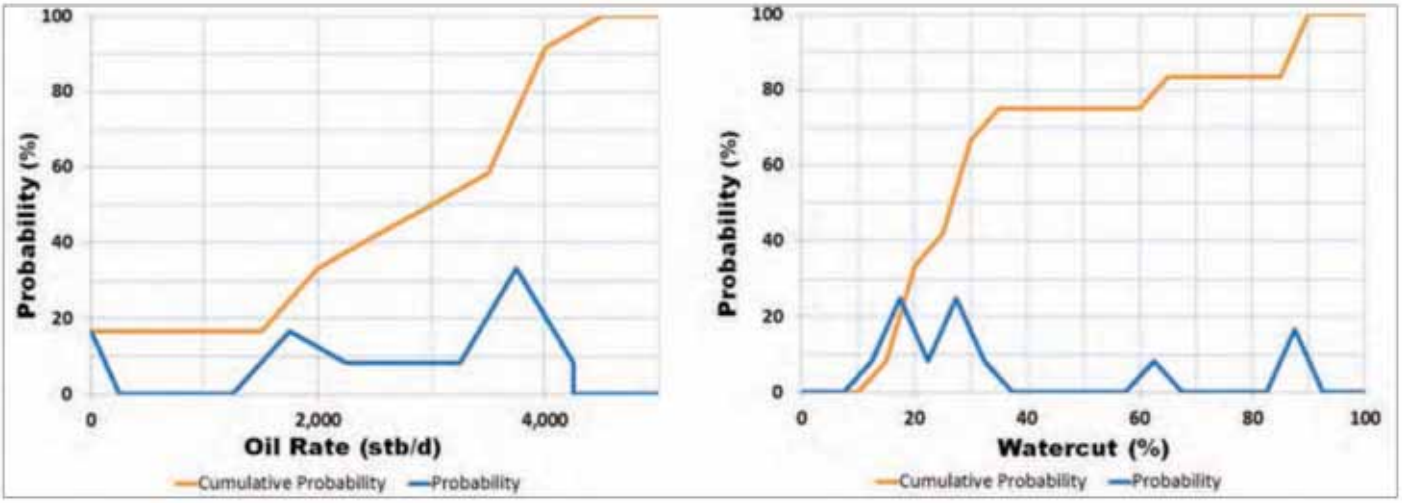

Fig. 6. First year oil production rate and water cut results distributions for all vertical/deviated wells put onstream since 2008.

such as production and injection performance by area, water cut and salinity profiles, mud-loss records in both reservoirs, image log surveys and seismic interpretations, have confirmed the presence of major fracture corridor systems in certain areas, which likely account for the vertical communication between the Upper and Lower reservoirs[4, 7].

In the structural positions where the basal part of the Upper reservoir has been swept by water, these vertical fractures create pathways for water gravity dumping from the Upper to Lower reservoirs. Another element of uncertainty is that the actual locations of these fracture communication pathways are not always known, which at times results in well logs showing unexpected water bearing fractures and a water imbibed matrix.

Combined Upper and Lower Reservoirs Simulation Model Utility and Limitations

A reservoir simulation model combining the Upper and Lower reservoirs is currently being used as a tool to guide field reservoir management. The Upper reservoir model is robust and is being used for reservoir studies, including well placement.

In the Lower reservoir, the reservoir fluid flow is totally dominated by the natural fracture system and its interaction with the low permeability matrix. There is no unique solution to the Lower reservoir history match problem[11]. The matrix-fracture exchange (imbibition) and the level of communication with the Upper reservoir can be adjusted to achieve an almost perfect history match for every probabilistic realization of the

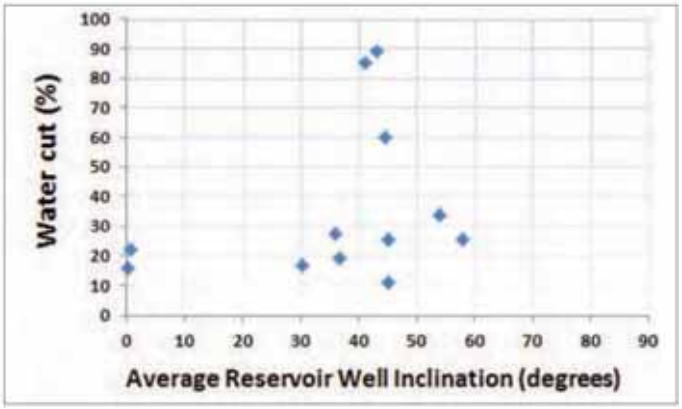

Fig. 7. Impact of well deviation on first year water cut in all vertical/deviated wells put onstream since 2008.

Lower reservoir fracture model. Each realization will locate Lower reservoir water away from well control in different positions in the model due to the different locations of the fracture corridors connecting the Upper and Lower reservoirs. As each realization is just as likely as the others, the simulation model cannot be utilized for new well placement studies.

Lower Reservoir Vertical/Deviated Well Production Performance

The Lower reservoir was originally developed with vertical wells supported by peripheral water injection. All wells drilled before 1980 were completed as perforated and stimulated cased hole completions. The vertical and deviated wells added during the 1990s, however, they were completed open hole. Both cased and open hole completions were unable to sustain flow prior to stimulation.

Since 2009, an active development program of vertical and deviated cased hole producers has commenced. Some of the new deviated wells that were added were sidetracked from high water cut Lower reservoir horizontal wells or were the result of deepening Upper reservoir wells. Prior to 2008, approximately 20 Lower reservoir vertical/deviated completions were produced. Since then, approximately 10 new cased hole producers have been added.

Vertical/Deviated Well Production Performance Results

Figure 5 presents the probabilistic distributions of the first-year average oil rate and water cut results for all the approximately 30 vertical and deviated wells historically produced in the Lower reservoir. Based on this data set, the mean oil rate and water cut were calculated as ~4,500 stock tank barrels per day (stb/d) and 16%, respectively. The 50% probability (P50) oil rate and water cut values are ~3,400 stb/d and 0%, respectively.

Figure 6 presents the probabilistic distributions of the first- year average oil rate and water cut results for the vertical and deviated wells put on production in the Lower reservoir during the last five years. The mean oil rate and water cut are ~2,500 stb/d and 36%, respectively. The P50 oil rate and water cut are ~2,900 stb/d and 25%, respectively.

In Fig. 7, the average first-year water cut for the vertical/deviated wells drilled during the last five years has been plotted against average well inclination across the reservoir section. Although there is no clear trend in this data set, it is apparent that all wells with high water cut were completed with more than 40° reservoir section inclination.

Fracture Impact on Vertical/Deviated Well Productivity and Well Performance

A bubble map of cumulative oil production for Wells V1, V2, V3 and V4 is presented in Fig. 8. Well V1 was put onstream in 1954 followed by other wells in the 1970s. Well V2 is located in the center of the field and is connected to more oil volume compared to the other three wells; however, it has lower cumu- lative production. There is no pressure issue supporting these wells' production.

PTA data reveals that Well V2 has a significantly higher productivity index (PI) and well flow capacity (*kh*). Lower reservoir matrix *kh* is generally uniform throughout the reservoir, with its value ranging from 400 to 600 mD-ft. A PTA log-log plot including Wells

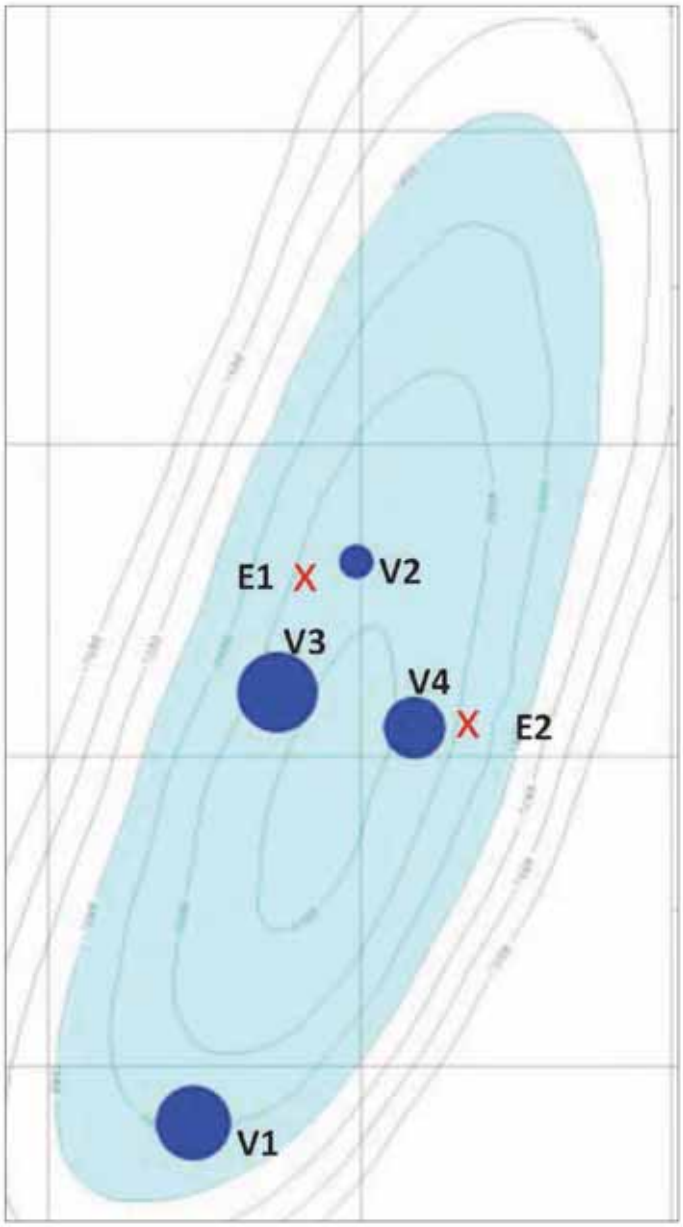

Fig. 8. Locations of vertical Wells V1, V2, V3, V4, E1 and E2 on bubble map of cumulative production.

V1, V2 and V3 is presented in Fig. 9. The PTA for these three Lower reservoir wells reveals significant fracture enhancements of flow capacity.

The degree of fracture enhancement of *kh* relates to the type of fractures influencing the well, i.e., large-scale fractures or small-scale (diffuse) fractures. It has been shown that an enhancement with a factor up to 10 times the core derived matrix *kh* indicates diffuse fractures causing a general improvement of matrix permeability[3, 12]. A large-scale dynamic fracture system (like an Upper reservoir communication fracture corridor) will cause a flow capacity improvement of a factor higher than 10.

For Wells V1, V2 and V3, the *kh* improvements (kh_D/kh_S) are 12, 32 and 4, respectively. The Fig. 9 log-log diagnostic plot shows that Well V2 does not directly intersect a large-scale fracture system, but the derivative response indicates a fracture system is located in the vicinity of the well. The vast improvement in Well V2 *kh* suggests that this well is located close to a fracture corridor communicating with the Upper reservoir. The significantly smaller Well V2 cumulative oil, compared

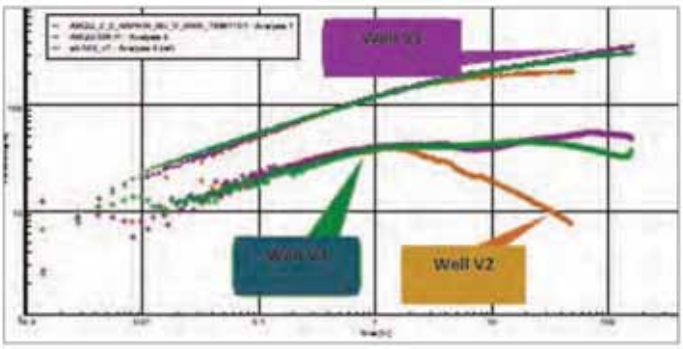

Fig. 9. Lower reservoir vertical Wells V1, V2 and V3 pressure transient log-log plot.

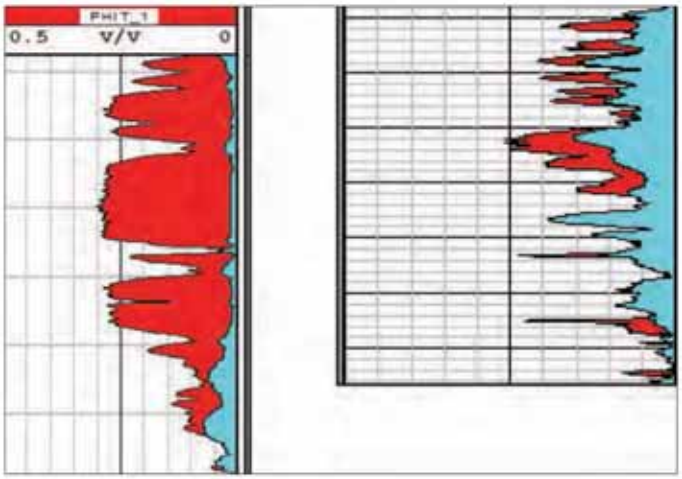

Fig. 10. Well E1 (left) and Well E2 (right) saturation log results (red: oil, blue: water).

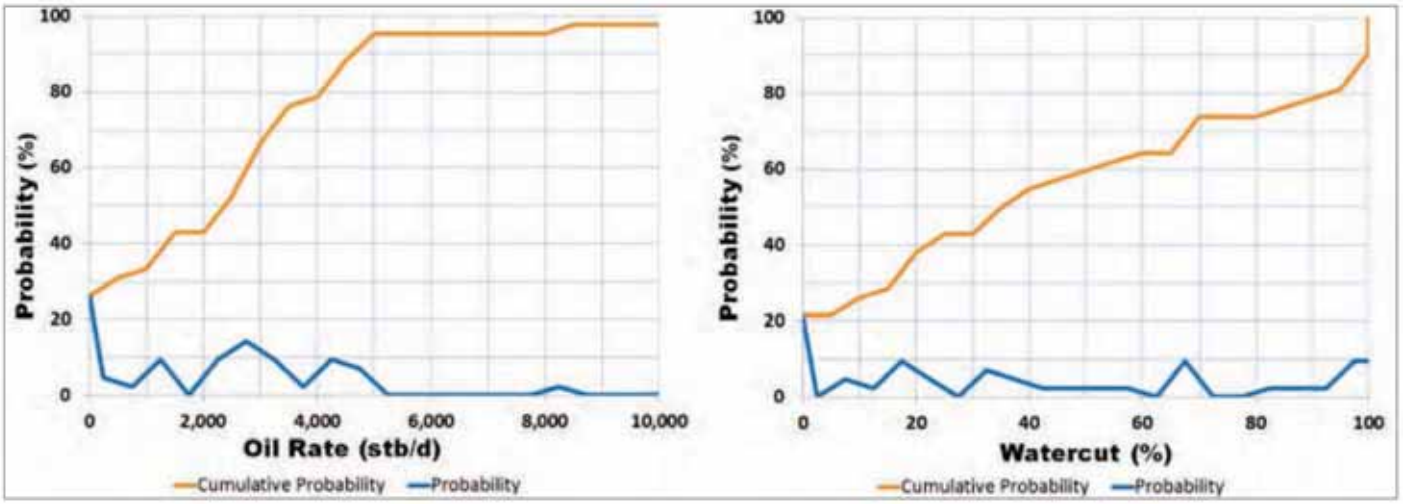

Fig. 11. First year oil production rate and water cut results distributions for all horizontal wells put onstream 1993-2012.

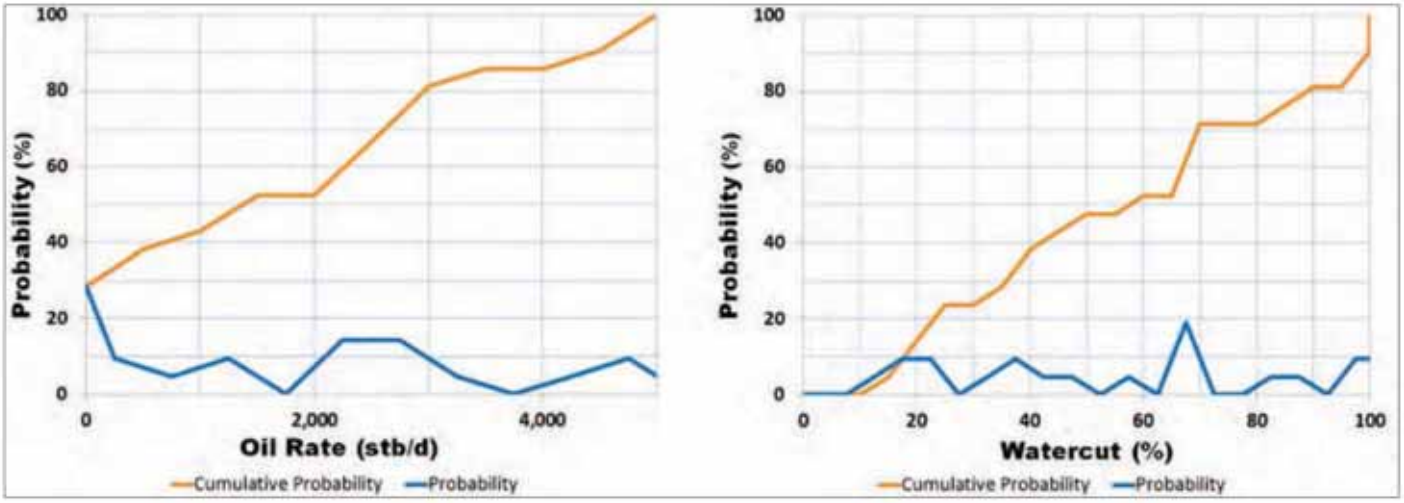

Fig. 12. First year oil production rate and water cut results distributions for all horizontal wells put onstream since 2008.

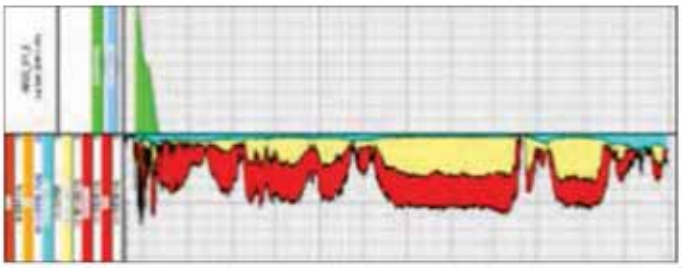

Fig. 13. Lower reservoir horizontal Well H1 production flow profile (green curve).

to other wells, as demonstrated in Fig. 8, is a result of excessive water production due to the well's close proximity to this fracture corridor.

Two evaluation wells recently drilled confirm this conclusion. Well E1, drilled down-dip of Well V2, encountered a full oil column. Well E2, drilled down-dip of Well V4, exhibited a fully swept matrix. The well locations and saturation logs for Wells E1 and E2 are shown in Fig. 8 and Fig. 10, respectively. Based on the information presented for these wells, it is evident that the large-scale fracture system tends to preferentially channel water from flank water injectors to crestal producers.

Lower Reservoir Horizontal Well Production Performancer

In the early 1990s, horizontal producers were introduced to the Lower reservoir development. By the late 1990s, after an active development program, most producers were single-lateral horizontal wells. The main objective of the horizontal well completions was to increase reservoir contact and improve well productivity. In total, the Lower reservoir has to date been produced by approximately 40 horizontal well completions or recompletions.

Horizontal Well Production Performance Results

Figure 11 presents the probabilistic distributions of the first-year average oil rate and water cut results for all horizontal completions historically produced in the Lower reservoir. The mean oil rate and water cut of this data set are ~2,500 stb/d and 44%, respectively. The P50 oil rate and water cut values are ~2,400 stb/d and 35%, respectively.

Figure 12 presents the probabilistic distributions of first-year average oil rate and water cut results for the horizontal wells put on production in the Lower reservoir during the last five years. The mean oil rate and water cut are ~1,700 stb/d and 56%, respectively. The P50 oil rate and water cut are ~1,300 stb/d and 59%, respectively. As shown in Fig. 12, 30% of the horizontal producers completed since 2008 were unable to flow after tie-in.

Fracture Impact on Horizontal Well Productivity and Well Performance

As well productivity is dictated by fractures; a horizontal well has a much higher chance to penetrate large-scale natural fractures than a vertical well since the large-scale natural fractures in this field are near-vertical features.

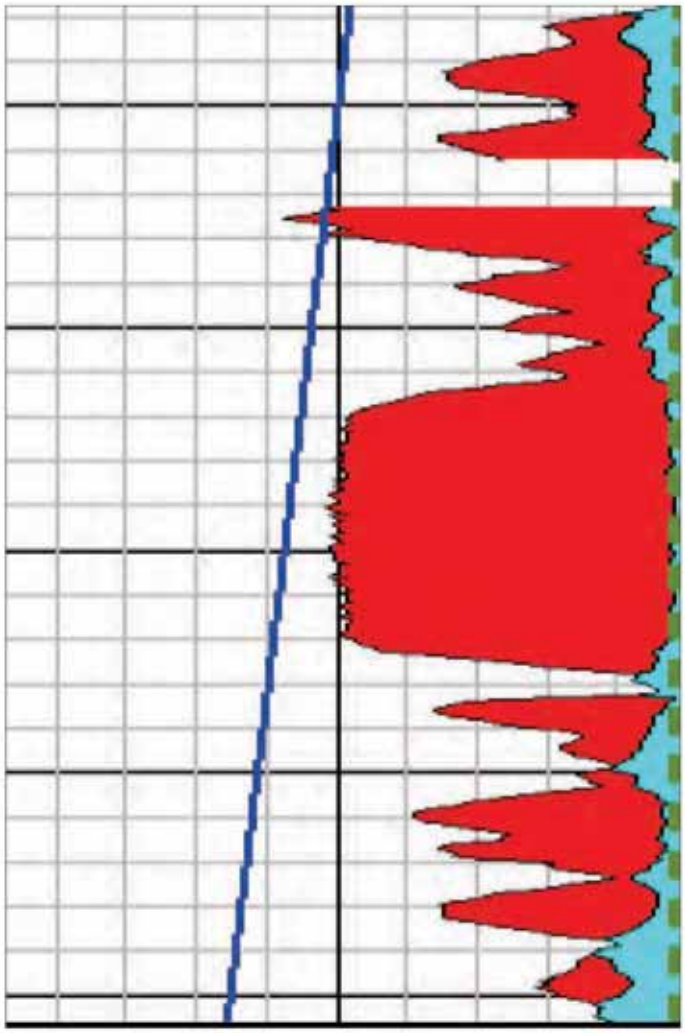

Fig. 14. Lower reservoir Well E3 saturation log results.

A horizontal well that penetrates large-scale fractures generally will have total circulation losses during drilling and a single or very few production entry points. The PI and flow capacity of this type of well can be extreme. The flow profile (provided by production logging tool) for Well H1, as displayed in green color in Fig. 13, is a typical production influx from this type of well.

Most of the horizontal wells drilled in the 1990s performed well. With the increasing reservoir maturity, however, the horizontal wells drilled in more recent times tend to produce at high initial water cut. The large-scale fractures that in the early development were filled with and produced oil, as observed in Well H1, are now filled with water. Evaluation Well E3 was drilled several years after Well H1 died due to high water cut, and it encountered significant oil column, as displayed in the saturation log, Fig. 14. Figure 15 presents the locations of Wells H1 and E3. This observation again confirms that production influenced by the large-scale fractures is prone to preferential channeling of water, as has been discussed in the vertical Well V2 case.

Some of the recently drilled horizontal wells did not experience circulation losses while drilling, and the image logs indicate that no major large-scale fracture corridors in those cases were penetrated. As shown in Fig. 16 for horizontal producer Well H2, an integration of production log and image log data reveals that some of these small-scale fractures are filled with oil and others with water. Extensive mini-DST surveys to evaluate these fractures have also led to the same conclusion[4]. A possible explanation for this behavior is that some of the small-scale fractures form extensive fracture swarms that may connect to a major large-scale fracture system some distance away from the wellbore. When the

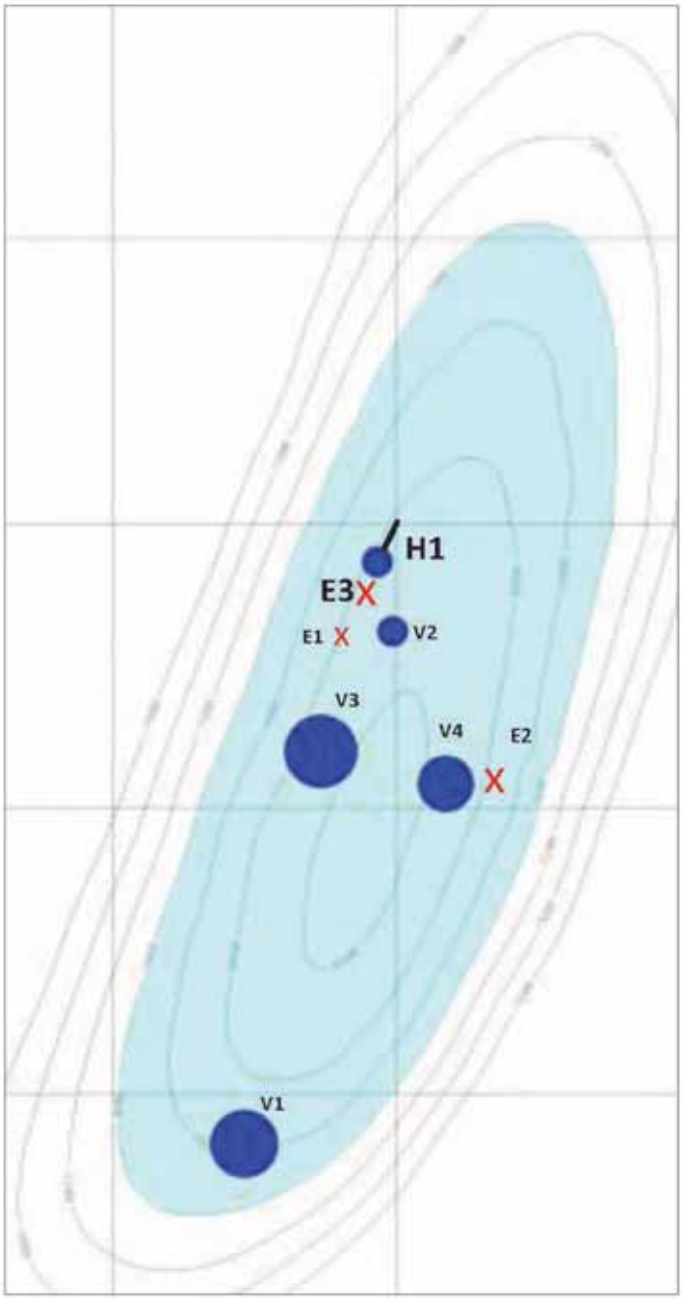

Fig. 15. The locations of Wells H1 and E3 on bubble map of cumulative production.

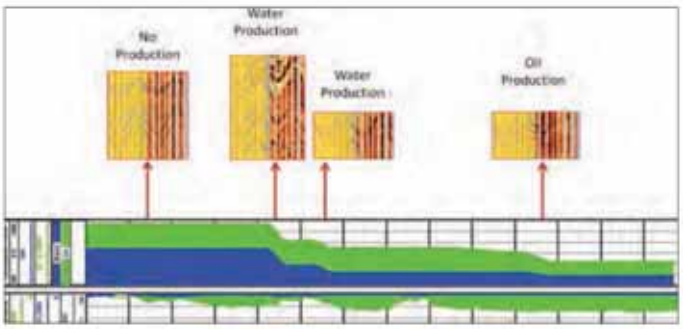

Fig. 16. Horizontal producer Well H2 flow meter profile and image log integration.

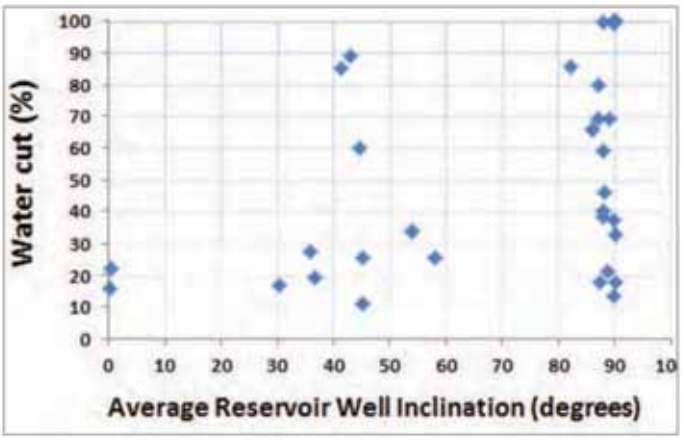

Fig. 17. Water cut as a function of well inclination for all Lower reservoir producers put onstream since 2008.

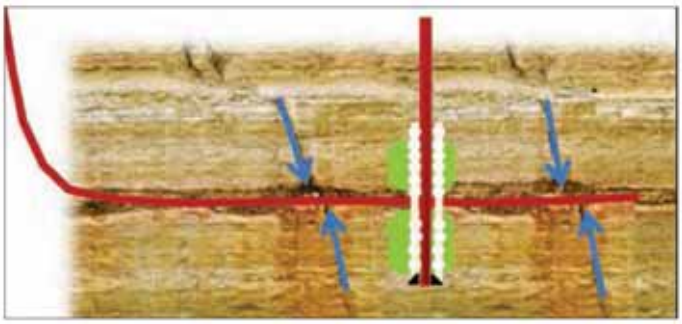

Fig. 18. Schematic cross section presenting horizontal well, vertical well and fracture corridors

major fracture system become wet, the fracture swarms connecting to both wells and large-scale fractures quickly become water filled due to the pressure sink at the well locations.

Lower Reservoir Cased Horizontal Producers and Advanced Completions

In the case of open hole horizontal producers that were unable to flow or produced at high water cut after tie-in, several different types of remedial actions have been employed:

- Perforated liners (41⁄2" and 7").
- Expandable liners or open hole clads for fracture isolation.
- Stage stimulation completions.
- Sidetrack to slanted cased producer.

Both the perforated liner and stage stimulation completions have largely been unsuccessful despite the availability of open hole image logs and production logs prior to the design of the remedial completions. It is likely the liner option has been unsuccessful due to the delicate cement job conditions that all operators face in cementing liners in horizontal wells. The stage stimulation completions are still under review, but it is possible that the packers need to be moved further away from the stimulated intervals. It is expected that the wet large-scale fracture systems that were intended to be isolated with blank pipe continue to contribute to fluid flow post-stimulation due to a leak across the packers.

The expandable liner and open hole clad completions for fracture isolation have in most cases been successful; however, a sidetrack to a slanted cased and perforated producer into a carefully picked area, based on the image and production logs from the watered out horizontal well, has proven to be the option with the best long-term production results.

Inflow control valves (ICVs) have been utilized for three new wells: two multilaterals and one single lateral application. The multilateral wells were unsuccessful since all laterals were producing at high water cut. The single lateral horizontal well with segmented ICV completion is currently one of the best performing wells in the Lower reservoir.

Comparison of Vertical/Deviated and Horizontal Producers in the Lower Reservoir Development

A comparison of the average oil rate and water cut of vertical and horizontal wells drilled in the Lower reservoir during the last five years indicate that vertical wells outperform the horizontal wells. The average first-year vertical/deviated producer oil rate and water cut was ~2,500 stb/d and 36%, respectively, compared to ~1,700 stb/d average oil rate and 56% average water cut for horizontal wells. As the mean horizontal well cost in the same period was more than 40% higher than the comparative cost of a vertical/deviated producer, the optimum development well type is a straightforward decision.

Figure 17 displays the first-year water cut outcome of all Lower reservoir producers completed in the last five years. This plot demonstrates that some of the horizontal producers were actually quite successful. Nevertheless, it is clear from this data set that the probability for a high water cut outcome grows with increased drilling deviation across the reservoir section.

The schematic Lower reservoir cross section, Fig. 18, offers an explanation for the increased probability of a high water cut outcome for horizontal wells. A horizontal well has a higher probability of intersecting major near-vertical large-scale fracture events. As many of these high conductivity fracture corridors are now filled with water, the outcome will be distinct water production entry points along the wellbore. In fact, this schematic horizontal well is not likely to be able to flow at normal operating pressure due to two water producing fracture corridors that will dominate the flow. A vertical well placed in between the two fracture corridors will produce water freely until matrix water breakthrough, which may take several years to occur.

In essence, the vertical wells are the optimum development solution solely as a risk management measure. If the exact locations of the water-bearing fracture corridors were known prior to drilling, this would allow the horizontal well trajectory to be drilled away from these fracture events. It is then likely that the horizontal producers would perform better than vertical wells since the horizontal well contacts more reservoir volume.

Conclusions

A detailed review of vertical and horizontal well production performance concludes that a vertical well is a better completion option than the horizontal well completions for the development of the low permeability, heavily fractured Lower reservoir. The following major observations were made in this case study:

- Horizontal wells penetrate many more natural fractures, including large-scale fracture corridors.

- At present, most major large-scale fracture systems tend to be water filled. As a result, horizontal wells tend to have a higher chance of producing with high initial water cut due to the higher probability of intersecting large-scale fracture systems with horizontal wells than with vertical wells.

- The most important factor in the Lower reservoir well placement is to adapt a strategy that minimizes the risk of penetrating water bearing fracture corridors that will yield high initial water cut.

- It is also concluded that production influenced by large-scale fractures, in either vertical or horizontal wells, tends to channel water more easily.

- The first-year production statistics for the wells put onstream over the last five years demonstrate that the average vertical/deviated producer has higher oil rate and lower water cut than the average horizontal well. In combination with higher horizontal well cost, the vertical/deviated wells are at present the optimum development well type.

Acknowledgements

The authors would like to thank Saudi Aramco management for the permission to present and publish this article. Special gratitude is expressed to Rodolfo Phillips Guerrero for his multitude of pressure transient interpretations that provided much insight into the fracture systems away from well control.

This article was presented at the 18th SPE Middle East Oil and Gas Show, Manama, Bahrain, March 10-13, 2013.

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Fahad is a member of the Society of Petroleum Engineers (SPE), and has served on several SPE forums and workshop committees. He was SPE Distinguished Lecturer in the subject of reservoir management in 2008-2009.

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Evolving Khuff Formation Gas Well Completions in Saudi Arabia: Technology as a Function of Reservoir Characteristics Improves Production

By Dr. Zillur Rahim, Dr. Hamoud Al Anazi, Adnan Al-Kanaan, Chris Fredd and Dr. M. Nihat Gurmen.

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Abstract

The Khuff formation is a late Permian age heterogeneous carbonate sequence that underlies the massive Ghawar field in eastern Saudi Arabia. The Khuff is subdivided into four separate intervals (A through D), though production is primarily from the B and C intervals. Since its initial appraisal in the late 1970s, the majority of Khuff development activity has been focused in the Khuff-C reservoir, where single and multistage matrix acidizing treatments have been the predominant stimulation technique.

As domestic gas demand in Saudi Arabia continues to rise, unrelenting efforts are underway to develop the tighter Khuff-B areas while sustaining production levels from Khuff-C wells. As a result, an increasing number of wells have been drilled and completed in the Khuff-B reservoir. The latest trends in the development of these tight gas Khuff wells include multistage acid fracturing to optimize the stimulation treatments.

Various drilling, completion, and stimulation techniques have been utilized in the Khuff development since its inception. Some of the variants analyzed to determine impact on production include: type of stimulation treatment, hole azimuth, completion isolation system, and number of stimulation stages per well. In addition, treatment design parameters were analyzed. Particular attention was paid to performance trends from Khuff-B wells where improved technical solutions were required to address challenging reservoir characteristics.

The results of this analysis demonstrate that multi- stage fracturing (MSF) technologies made a positive impact on Khuff development — with improved production results over time. Trends also highlight an increase in stimulation stage count and a wider range of stimulation treatments with the application of new technologies. The analysis identified the key production drivers in the Khuff and ways to improve production of future wells drilled in the formation. Continued use of MSF has proven very successful in providing substan- tially higher rates and sustained production of the Khuff reservoir.

Introduction

Khuff reservoir development activity has deployed a wide array of completion techniques ranging from single stage vertical wells to multistage horizontal wells. A commonly referred challenge of carbonates is the fact that they are heterogeneous, geologically complex, and

Fig. 1. Carbonate rock outcrop indicates heterogeneity (Photo courtesy of Mohammad Reza Saberi, University of Bergen).

difficult to characterize. Unlike sandstones, with their well-behaved correlations of porosity, permeability and other reservoir properties, the heterogeneous pore systems of carbonate rocks defy routine petrophysical analysis. Carbonates are deposited primarily through biological activity, resulting in a rock that is composed of fossil fragments and other grains of widely varying morphology — and commonly has pores with highly complex shapes and sizes, Fig. 1.

As the focus shifted to tighter reservoirs over the years, the well completions have evolved in the Khuff formation from vertical wells that were stimulated to multilaterals and finally to multistage fracturing (MSF) treatments. The success in MSF treatments is depicted in Fig. 2 where the productivity increase is distinct from the other completion methods. This article takes a critical look at these evolutionary steps and analyzes their success rate based on the impact they have on production. During the analysis the effect of the inherent complexity of the carbonate reservoirs and the variability from its giant dimensions as well as strategies to cope with them are discussed.

Khuff Formation Geology

The Khuff formation represents the earliest major transgressive carbonate deposited on a shallow continental shelf in eastern Saudi Arabia. As expected, due to its colossal dimensions, the reservoir properties can vary significantly. The Khuff formation was deposited in tidal flat environments, including subtidal, intertidal and sabkha (supratidal) environments. These depositional environments represent four major cycles, Khuff-D, Khuff-C, Khuff-B and Khuff-A, in an upward sequence, Fig. 3. Each cycle starts with a transgressive grainstone facies that makes up the Khuff reservoirs and ends with regressive, muddy and anhydritic facies, which make up the non-reservoir units1.

Development of reservoir quality appears to be complexity controlled by lateral continuity or discontinuity of depositional facies. Due to these lateral changes, Khuff reservoir development does not exactly follow structural position. Wells situated structurally high do not necessarily exhibit the best reservoir characteristics. Rock diagenesis has also increased or decreased reservoir quality. In some places, dolomitization and leaching have enhanced the reservoir quality but opposite to that we have other places where dolomitization and cementation have serious impact in both porosity and permeability[1]. There is a general trend in which the reservoir quality deteriorates in the northern direction.

Khuff is a high-pressure, high temperature carbonate reservoir with two main gas bearing layers, dolomitic and tight Khuff-B and the more prolific calcite Khuff-C. The reservoir exhibits extensive heterogeneity in stress, reservoir quality, and reservoir fluids throughout the field. This heterogeneity combined with the deep and hot nature of the reservoir, has made it a challenging task in achieving uniform and effective stimulation of all layers[2, 3]. Consequently, well production potential can significantly fluctuate if treatments are not optimized.

The reduction in variability in production has been the goal throughout the history of Khuff reservoirs. From simple acid washes to major acid fracturing operations,

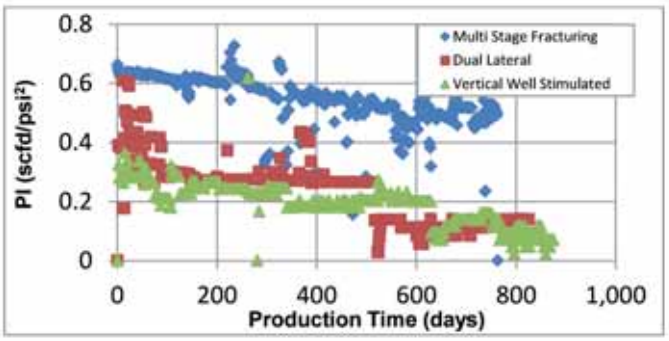

Fig. 2. PI for different completion types.

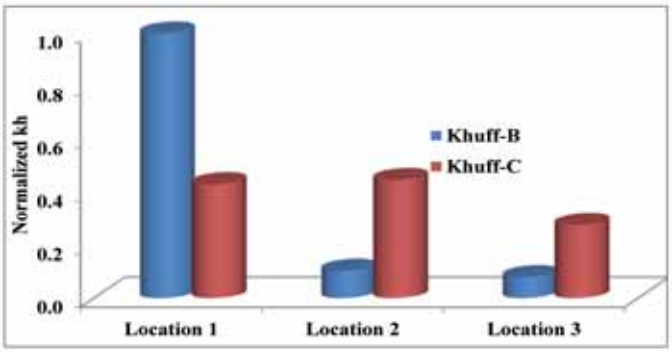

Fig. 4. Variation in kh.

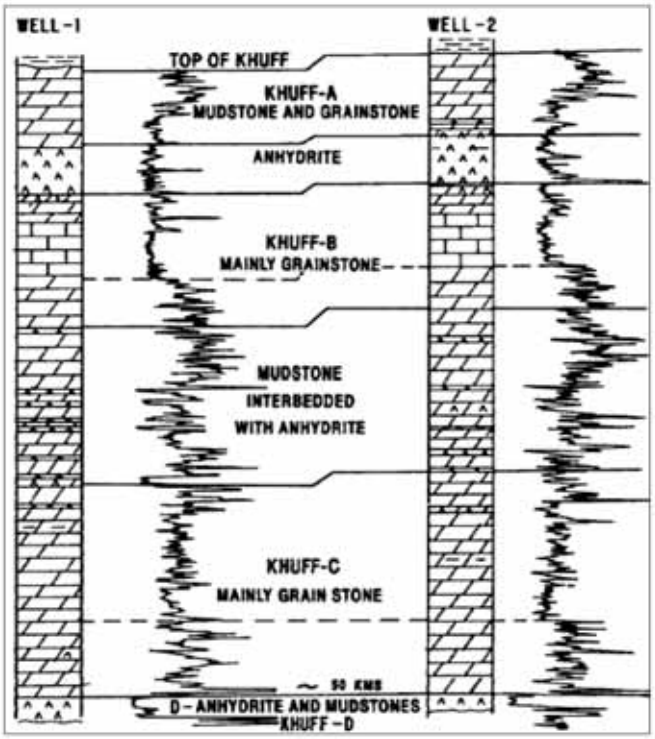

Fig. 3. Khuff main lithofacies and gamma ray correlation.

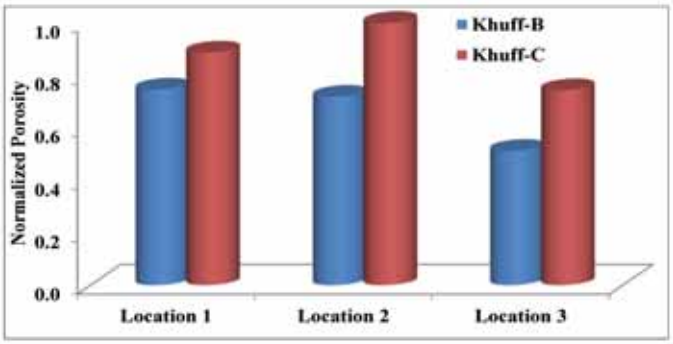

Fig. 5. Variation in porosity.

every carbonate stimulation technology has found an application over the years in these reservoirs. Parallel to the advances in the chemistry of fluid technologies, the completion techniques also evolved through the application of many different cased and open hole technologies. Saudi Aramco's rigorous evaluation in its laboratory and in the field ensured that only the most useful technologies survived the test of time. The next section will go over these various technologies along with a historical relevance to the changes in the Khuff reservoirs.

Heterogeneity in the Khuff Formation

As domestic gas demand in Saudi Arabia continues to rise, unrelenting efforts are underway to develop the tighter Khuff-B areas while sustaining production levels from Khuff-C wells. Figures 4 and 5 show the trends in formation conductivity (*kh*) and porosity at different points in the field showing wide heterogeneity.

Although the characteristics of Khuff-C are relatively uniform, the *kh* variation in Khuff-B is noticeable, making this reservoir more challenging to develop.

To better understand the reservoir characteristics, most acid fracturing treatments pumped in the Khuff formation include a small treatment prior to the actual job, often called a datafrac or minifrac. A minifrac is a series of injections conducted on the well prior to stimulation to obtain a few important reservoir and fracturing properties[4]. Among these properties are the formation breakdown, extension, and closure pressures and fluid leakoff parameter. These numbers are important to optimize subsequent fracturing operation and predict pumping pressures. The minifrac usually consists of a breakdown test (with water) followed by a short pressure fall off, step rate test (with water), and a calibration test (with actual gel fluid). Table 1 provides the different tests and the properties that are computed from each of the steps. The *kh* is an important variable that can be estimated from the minifrac and used to estimate well potential. An example of a minifrac treatment is shown in Fig. 6 and the diagnostics plots to compute reservoir and fluid properties, including rock

Test Name	Steps	Fluids	Parameters
Breakdown	Injection	Water or linear gel	Formation breakdown pressure Transmissibility *kh*/μ Reservoir pressure
	Shut-in and fall off		Fracture closure pressure
Step Rate	Step up (injection)		Fracture extension rate and pressure
	Step down (injection)		Near wellbore friction
Calibration	Injection	Cross-linked gel	Fracture geometry
	Shut-in		Fracture closure pressure Fluid efficiency, leakoff

Table 1. Typical parameters computed from minifrac test data

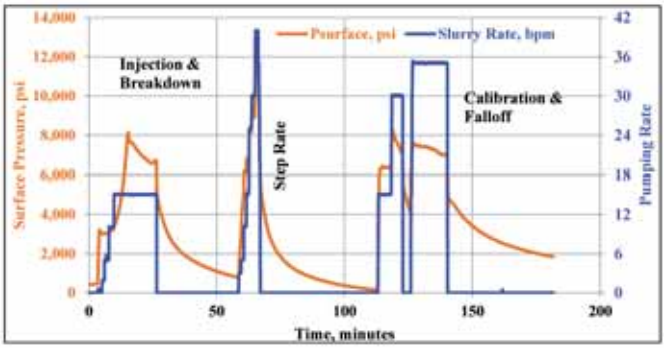

Fig. 6. Typical minifrac treatment in the Khuff

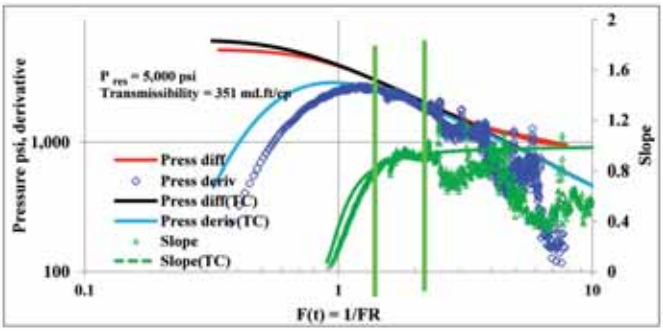

Fig. 8. Type curve match to compute reservoir transmissibility.

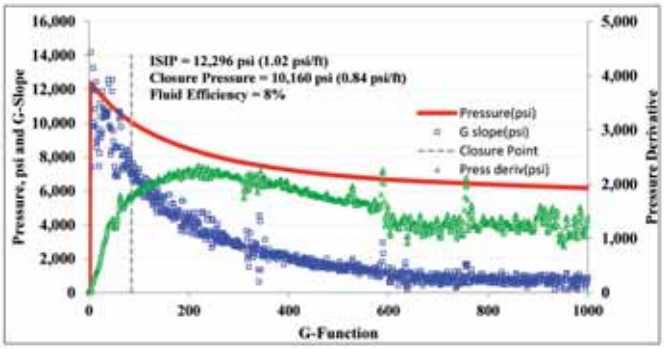

Fig. 7. G-Function plot to compute fracture closure pressure

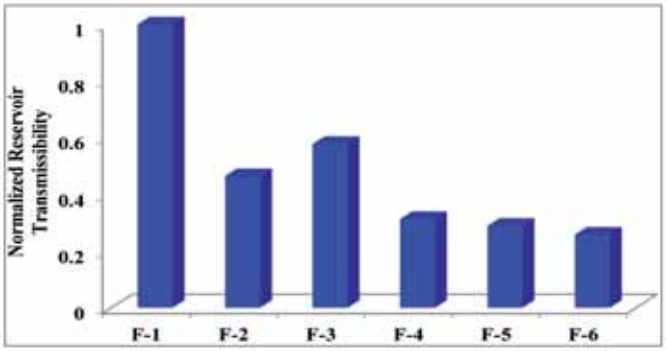

Fig. 9. Normalized transmissibility variation in different Saudi Arabian fields (normalized).

transmissibility are provided in Figs. 7 and 8.

During a period from 1998 to 2012, numerous fracturing treatments were performed in four different formations accessed from five main Saudi Arabian fields. The average values of fluid flow parameters presented in Fig. 9 and fracture parameters in Table 2 illustrate the heterogeneity among the formations.

In general, the Khuff carbonate has a higher fracture gradient (FG) when compared with sandstone formations. This higher FG results in higher pumping pressure and difficulty in breaking down the formation. Khuff also has good transmissibility values (*kh*/μ), which represent the reservoir flow capacity. Many of the Khuff wells respond very positively to stimulation and deliver good production.

Historic Trends: Improvement in Stimulation and Completion Technologies

Stimulation treatments in Saudi Arabian nonassociated gas reservoirs started in 1998. Since then, stimulation technologies have become widely used and an assessment of well response due to stimulation has shown substantial improvement in production. Recently, hydraulic fracturing has become a normal practice, particularly in moderate to tight gas reservoirs. The improvement and optimization to fracturing technology, however, is a continuing process. Figure 10 shows the normalized job count since 1998 with a mixture of matrix

Field	F-1	F-2	F-3	F-4	F-5	F-6
Total number of wells in analysis	18	21	11	10	12	1
FG_{avg}, psi/ft	0.79	0.79	0.88	0.78	0.77	0.87
FG_{max}, psi/ft	0.97	0.96	1.05	1.08	1.06	0.91
ΔP_{net}, psi	620	870	620	760	470	1,250
F_{eff}, %	13	27	20	30	25	35
P_{clos}, psi	10,610	11,165	12,090	12,400	10,340	13,320
R_{trans}, md-ft/cp	1,275	590	735	400	370	330
P_{res}, psi	7,560	9,625	9,100	8,850	8,000	9,670

Table 2. Reservoir and fracture property variation in Saudi Arabian fields

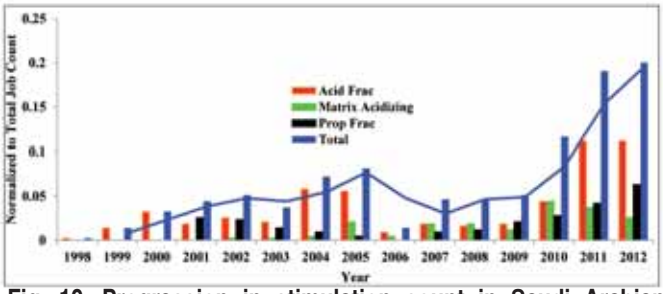

Fig. 10. Progression in stimulation count in Saudi Arabian reservoirs.

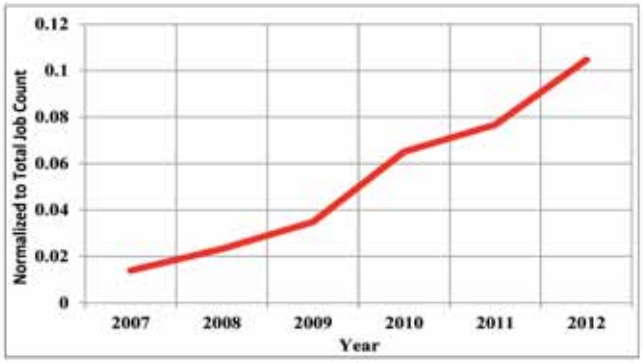

Fig. 11. Progression in MSF count in Saudi Arabian reservoirs.

acidizing, fracture acidizing, and proppant fracturing — in sandstone formations. There is a clear increase in the number of stimulation treatments in recent years with about 22% of the total treatments occurring in 2012. A similar increasing trend in MSF treatments is shown in Fig. 11. These trends are a direct consequence of the good production response obtained from fracturing.

As the stimulation techniques evolved over time, water-based and acid-based polymer fracturing fluids and diverters were first used, followed by polymer-based self-diverting acid systems, and more recently by polymer-free viscoelastic acid systems[5, 6]. Significant optimization steps, derived from field experience and post-stimulation results have also been consistently applied, so a reduction of the initial pad volume was achieved without negatively impacting fracture requirements and performance while still reducing pumping time and fluid costs[3].

Improvement in stimulation fluid technologies was particularly important as the number of stimulation treatments increased and naturally led to an increase in the volume of stimulation fluids required to optimally treat all intervals. The fluid volume increase somewhat affected the well economics and a more effective acid diversion system was needed to ensure that proper stimulation could be achieved in intervals with varying reservoir properties without significantly increasing the acid volume. The utilization of polyacrylamide-based

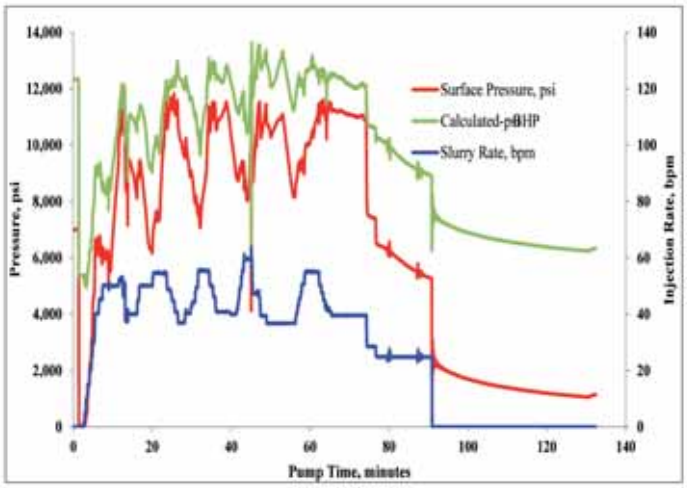

Fig. 12. Acid fracturing treatment showing diversion effects.

diverters showed diversion improvement in a number of treatments. In 2007, the introduction of a degradable fiber-laden viscoelastic surfactant-based diverter technology significantly improved post-treatment performance as indicated by studies comparing well performance in areas of the field with similar reservoir characteristics[7]. The diversion technology allowed for a reduction in diverter volume, yet still effectively treating all intervals. The high performance diversion efficiency of this new diverter system can be utilized in two different modes. In the first mode, one can target a gas production that is already achieved with conventional fluids and

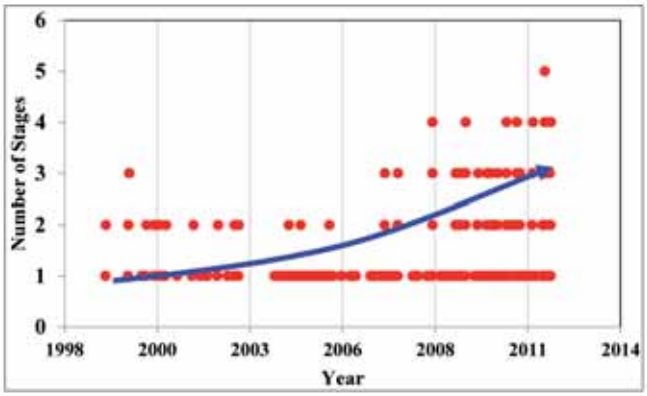

Fig. 13. Increasing number of MSF stages per well.

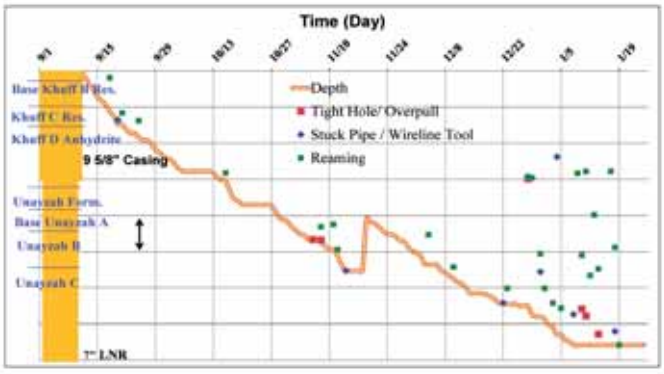

Fig. 14. Drilling events without the aid of geomechanics.

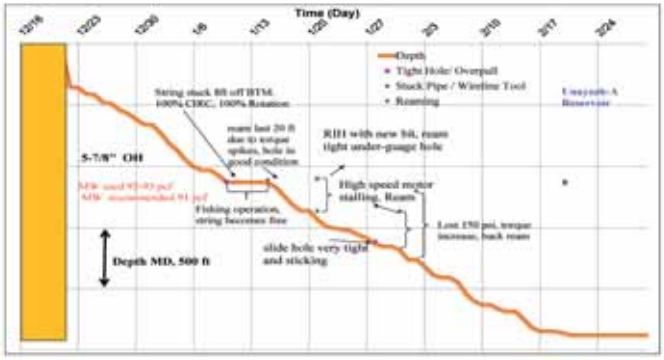

Fig. 15. Reduction in drilling events with geomechanics

apply the technology to optimize the acid volume and reduce the associated treatment cost. In the second mode one can target to maximize the gas production as much as possible increasing the total treatment volume. In this mode the new diverter enables more efficient use of the increased total acid volume and creates more reservoir contact area for hydrocarbon flow. Later in Figs. 20 and 21, it will be shown that the second mode of operation is mostly favored in Saudi Arabia due to the increased demand for gas. Figure 12 shows a typical multistage stimulation treatment where the pressure cycles depict the impact of multiple stages of fluid diverter system used to enhance uniform stimulation to the exposed reservoir intervals.

The increase in MSF treatments and the move towards tighter areas of Khuff reservoirs necessitated evaluation of multistage technologies utilized around the world to develop similar reservoirs. The application of completion methods using multistage assemblies provided a step forward in the application of stimulation technology in Saudi Arabian reservoirs. The multistage assemblies eliminated the use of through tubing bridge plugs for isolation and provided a significant reduction in the operation time. They also allowed for open hole connectivity with the reservoir, and thereby benefited the production in moderate permeability reservoirs compared to the plug-and-perf approach with cemented completions.

In 2006, the first open hole multistage completion was trial tested with a ball-sleeve type system. The assembly was successfully deployed and the post-fracture production rate exceeded expectations. With that success, engineers were motivated to use this technology on a wider scale. Figure 13 shows the increase in stage count per well, with lateral lengths relatively constant at around 3,000 ft. This increase in MSF stage count was better enabled by the adoption of open hole multistage completion technologies.

Another major accomplishment is the use of real-time geomechanics to improve drilling quality and to re-orient the wellbores toward the minimum in-situ stress (σ_{min}) direction to achieve transverse or orthogonal fractures[8]. The geomechanical calculations have helped tremendously in achieving wellbore stability with the prediction of correct mud weight to reduce borehole breakouts or breakdowns. Figures 14 and 15 shows, respectively, the initial drilling without the use of geomechanics and the reduction in drilling events due to application of real time analysis on data acquired by logs and borehole cuttings. Among other benefits, drilling toward σ_{min} also allows more fractures to be placed along a wellbore without having one fracture overlap the adjacent one. Once this strategy was implemented, the number of created independent fractures was increased, which improved the overall well production rate. Previously, wells were drilled in the direction of maximum in-situ stress (σ_{max}) resulting in longitudinal fractures during hydraulic fracturing treatments. Often times, such a setup did not provide enough isolation between stages, thereby causing fewer independently created fractures than designed.

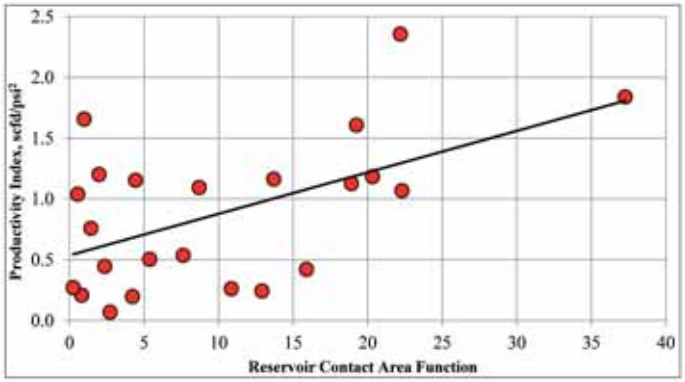

Fig. 16. Improved PI with higher reservoir contact.

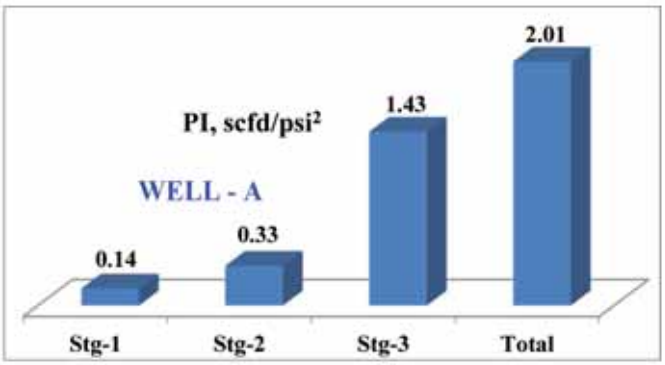

Fig. 18. Well-A productivity improvement with three stage treatment.

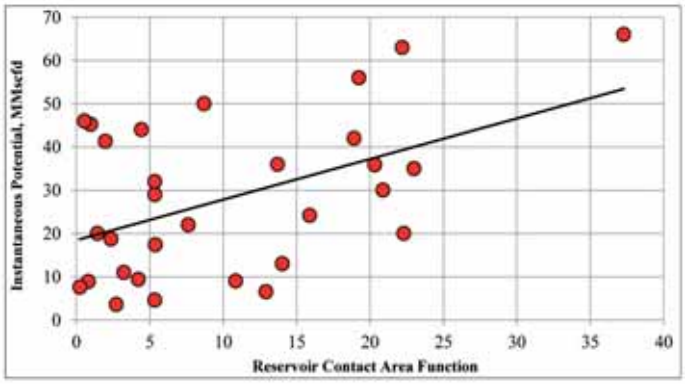

Fig. 17. Improved gas rate with higher reservoir contact.

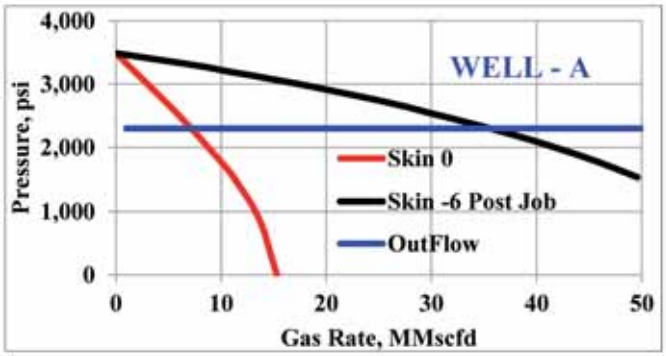

Fig. 19. Well-A inflow performance relationship curves showing well performance

Analysis of Multistage Stimulation Performance: Impact of Reservoir Contact

Saudi Aramco carbonate wells are stimulated with a range of fluid systems and methodologies depending on the reservoir characteristics and production expectations[9]. As a result, there is a significant difference in the amount of reservoir contact surface area that can be achieved during stimulation. To take these differences into account, the total post-stimulation reservoir contact area is computed based on fracture data analysis and a reservoir contact area function (RCAF) is used for interpreting the production results. The RCAF is a combination of both reservoir charac- teristics and completion characteristics, such as fluid mobility, fracture properties, and open hole geometry. The analysis shows that the productivity index (PI) and initial gas rate both increase with increasing RCAF, Figs. 16 and 17. Such trends were not observed when analyzing production performance relative to just reservoir characteristics. The RCAF values are significantly different for the three cases, Fig. 2, for the various completion methods of MSF (RCAF = 20), open hole dual lateral (RCAF = 0.0014), and open hole vertical well (RCAF = 0.0002). In the 33 wells evaluated in this study, 62% to 99% of the total surface area (open hole section plus fractures) is created by the hydraulic fractures. Therefore, the surface areas created by the hydraulic fracturing treatments are dominating the production results.

The production results were also analyzed to understand the impact of fracturing on a per stage basis. Figures 18 and 19 illustrate the PI increase and nodal analysis for a three stage acid fracturing treatment performed on Well-A. Nodal analysis highlights the improvement from an un-stimulated production rate of about 9 million standard cubic ft per day (MMscfd) compared to a post-stimulation production rate of about 36 MMscfd. The PI data clearly show improvement with each fracturing stage. The same trend is observed for the overall performance of the 33 wells in this study, with an increase in PI obtained with an increase in the number of fracturing stages, Fig. 20. Production simulations were performed to demonstrate the potential impact of adding additional transverse hydraulic fracturing stages to Well-A, Fig. 21. The results indicate that the production rate would continue to increase with increasing stage count up to eight stages, above which there is only moderate additional gains in

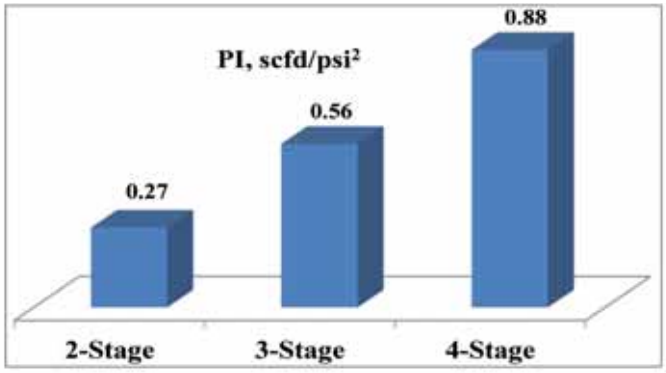

Fig. 20. Improved PI with successful MSF treatments evaluated in 33 wells.

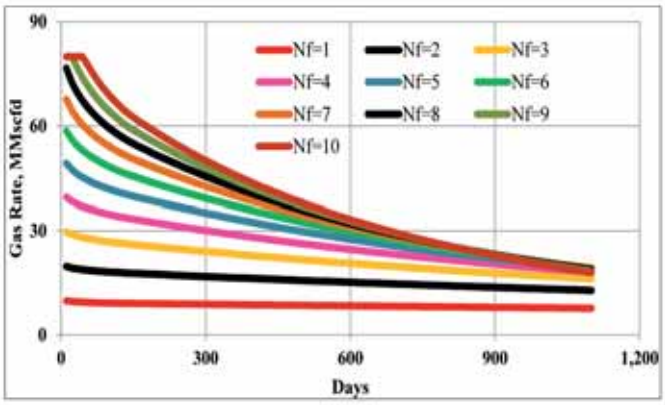

Fig. 21. Production simulation showing the impact of increasing number of fracturing stages (Nf).

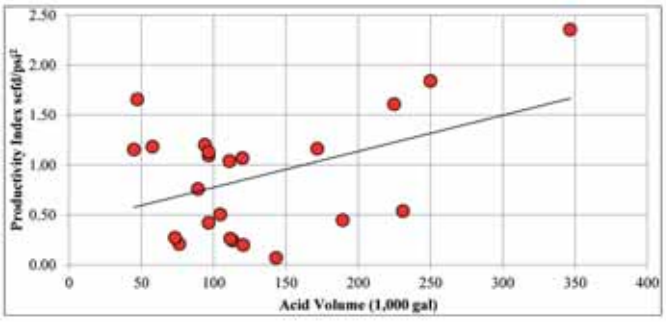

Fig. 22. Improved PI with increased volume of treatments.

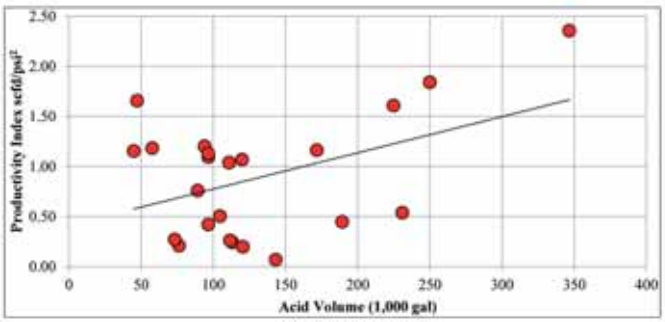

Fig. 23. Improved PI per stage with more acid.

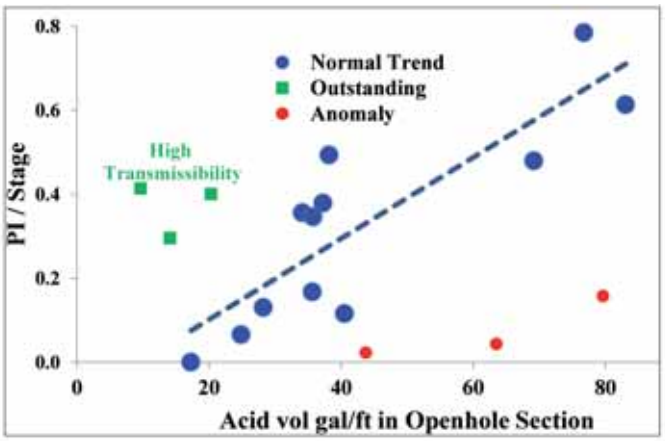

Fig. 24. Fracture geometry profile at the end of the treatment.

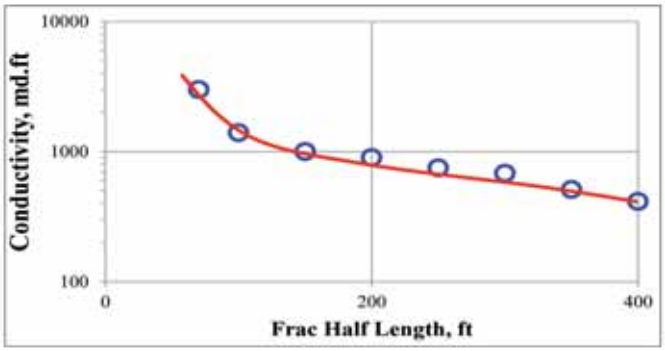

Fig. 25. Conductivity calculated from well production response.

production for this set lateral length of 3,000 ft and these well conditions. Therefore, Well-A could benefit from additional fracturing stages to further increase the reservoir contact surface area. These trends for the Khuff formation are consistent with the impact of MSF reported for the James Lime formation, where the production also increased with an increasing number of transverse fracturing stages[10].

Considerations for Continued Improvement

With the ongoing objective of optimizing the completion and stimulation strategies for the Khuff formation, the various stimulation designs were analyzed in more detail. There are insignificant variations in the completion and stimulation strategies used in Khuff-B and Khuff-C formations. Subsequently, there is a significant difference in how the tighter formations are stimulated — the use of more acid, diversion, and increased stages are a few of the important variables to ensure good stimulation and productivity[11]. The positive impact of increased acid volume on well productivity is demonstrated in Figs. 22 and 23.

Figure 24 illustrates the simulated acid etched profile achieved for a typical acid fracturing treatment. This profile compares well with the calculated conductivity and etched fracture half-length based on actual production response, Fig. 25. The example illustrates

good conductivity within a fracture length ranging between the wellbore and 130 ft (width varying between 0.6" and 0.15", Fig. 24). The conductivity gain is between 2,000 md-ft and 3,000 md-ft[12].

As a final point, the trend of increasing production with improved stimulation treatments (more RCAF and more acid volume) is observed in the majority of cases; however, there are some anomalies with less effective performance in three of the Khuff wells (labeled as anomalies in Fig. 23). These anomalies can be attributed to not achieving sufficient acid etched conductivity along the length of the fracture. There is a significant difference in the achieved acid etched length in high temperature areas where the acid reaction rate significantly increases and adversely affects the reservoir contact area. This suggests poor connection to the created conductivity in fractures and/or the inability to etch all of the surface area initially created by the pad sequence, due to rapid acid spending at high temperatures. In such condition, there is an opportunity for further optimization of the hydraulic fracturing treatments to achieve more effective reservoir contact surface area. For example, more effective stimulation techniques may involve more fracturing stages, larger acid volumes, the use of more advanced fluids, additional diverting stages, or even the use of proppant fracturing treatments in carbonate reservoirs.

Overall, the results of this study demonstrate the importance of achieving long effective fracture lengths and ensuring sufficient conductivity so the created surface area maintains connection to the wellbore. These key hydraulic fracture design considerations become even more important for delivering production as development extends into ever more challenging deep tight carbonate formations.

Conclusions

1. MSF treatments significantly increase the reservoir contact area relative to typical open hole completions. Multistage acid fracturing has proven beneficial in treating moderate to low permeability Khuff wells resulting in high gas production rates.

2. When compared with results obtained from open hole horizontal or dual lateral completions, the PI achieved with MSF treatments has shown higher rates.

3. To date, numerous Khuff wells have been successfully treated with acid fracturing and the process is ongoing on a routine basis.

4. The increased number of hydraulic fracturing stages has contributed to higher production rates.

5. The PI and initial gas production rate both increased with increasing the RCAF.

6. The application of appropriate stimulation technologies, such as fiber-based diverters, have allowed for optimization of the acid volume and reaction, further leading to increased production.

7. Changing the drilling direction from σ_{max} to σ_{min} has allowed the placement of many independent transverse fractures in the same wellbore (and increasing the reservoir contact surface area). Real- time geomechanics has been effective and is essential to obtaining borehole stability.

Nomenclature

Nf	Fracture Stages
TC	Type Curve
P_{res}	Reservoir Pressure
P_{clos}	Closure pressure
R_{trans}	Reservoir transmissibility
μ	Fracture fluid viscosity
FR	Dimensionless radial flow time function
$P_{surface}$	Surface Pressure
F_{eff}	Fracture fluid efficiency
G-function	Nolte G-function (fracture pressure parameter)
ΔP_{net}	Net Pressure
F(t)	Inverse time function

Acknowledgements

The authors thank Saudi Aramco for permission to publish this article and Schlumberger for its technical support and assistance.

This article was presented at the SPE Middle East Unconventional Gas Conference and Exhibition, Muscat, Oman, January 28-30, 2013.

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Biographies

Dr. Zillur Rahim is a Petroleum Engineering Consultant with Saudi Aramco's Gas Reservoir Management Department (GRMD). He heads the team responsible for stimulation design, application and assessment for GRMD. Rahim's expertise includes well stimulation, pressure transient test analysis, gas field development, planning, production enhancement, and reservoir management. Prior to joining Saudi Aramco, he worked as a Senior Reservoir Engineer with Holditch & Associates, Inc., and later with Schlumberger Reservoir Technologies in College Station, TX, where he used to consult on reservoir engineering, well stimulation, reservoir simulation, and tight gas qualification for national and international companies. Rahim is an Instructor of petroleum engineering industry courses and has trained engineers from the U.S. and overseas. He developed analytical and numerical models to history match and forecast production and pressure behavior in gas reservoirs. Rahim developed 3D hydraulic fracture propagation and proppant transport simulators and numerical models to compute acid reaction, penetration, and fracture conductivity during matrix acid and acid fracturing treatments.

Rahim has authored 65 Society of Petroleum Engineers (SPE) papers and numerous in-house technical documents. He is a member of SPE and a technical editor for the Journal of Petroleum Science and Engineering (JPSE). Rahim is a registered Professional Engineer in the State of Texas and a mentor for Saudi Aramco's Technologist Development Program (TDP). He is an instructor of the Reservoir Stimulation and Hydraulic Fracturing course for the Upstream Professional Development Center (UPDC) of Saudi Aramco. Rahim is a member of GRMD's technical committee responsible for the assessment and approval of new technologies.

Rahim received his B.S. degree from the Institut Algerien du Petrole, Boumerdes, Algeria, and his M.S. and Ph.D. degrees from Texas A&M University, College Station, TX, all in Petroleum Engineering.

Dr. Hamoud A. Al-Anazi is the General Supervisor of the North Ghawar Gas Reservoir Management Division in the Gas Reservoir Management Department (GRMD). He oversees all work related to the development and management of huge gas fields like Ain-Dar, Shedgum and'Uthmaniyah. Hamoud also heads the technical committee that is responsible for all new technology assessments and approvals for GRMD. He joined Saudi Aramco in 1994 as a Research Scientist in the Research & Development Center and moved to the Exploration and Petroleum Engineering Center – Advanced Research Center (EXPEC ARC) in 2006. After completing a one-year assignment with the Southern Area Reservoir Management Department, Hamoud joined the Gas Reservoir Management Division and was assigned to supervise the SDGM/UTMN Unit and more recently the HWYH Unit. With his team he successfully implemented the deepening strategy of key wells that resulted in a new discovery of the Unayzah reservoir in UTMN field and the addition of Jauf reserves in the HWYH gas field.

Hamoud's areas of interests include studies of formation damage, stimulation and fracturing, fluid flow in porous media and gas condensate reservoirs. He has published more than 50 technical papers at local/international conferences and in refereed journals. Hamoud is an active member of the Society of Petroleum Engineers (SPE) where he serves on several committees for SPE technical conferences. He is also teaching courses at King Fahd University of Petroleum and Minerals (KFUPM), Dhahran, Saudi Arabia, as part of the Part-Time Teaching Program.

In 1994, Hamoud received his B.S. degree in Chemical Engineering from KFUPM, and in 1999 and 2003, respectively, he received his M.S. and Ph.D. degrees in Petroleum Engineering, both from the University of Texas at Austin, Austin, TX.

Adnan A. Al-Kanaan is the Manager of the Gas Reservoir Management Department (GRMD) where he oversees three gas reservoir management divisions. Reporting to the Chief Petroleum Engineer, Adnan is directly responsible for making strategic decisions to enhance and sustain gas delivery to the Kingdom to meet its ever increasing energy demand. He oversees the operating and business plans of GRMD, new technologies and initiatives, unconventional gas development programs, and the overall work, planning and decisions made by his more than 70 engineers and technologists.

Adnan has 15 years of diversified experience in oil and gas reservoir management, full field development, reserves

assessment, production engineering, mentoring young professionals and effectively managing large groups of professionals. He is a key player in promoting and guiding the Kingdom's unconventional gas program. Adnan also initiated and oversees the Tight Gas Technical Team to assess and produce the Kingdom's vast and challenging tight gas reserves in the most economical way.

Prior to the inception of GRMD, he was the General Supervisor for the Gas Reservoir Management Division under the Southern Reservoir Management Department for 3 years, heading one of the most challenging programs in optimizing and managing nonassociated gas fields in Saudi Aramco.

Adnan started his career at the Saudi Shell Petrochemical Company as a Senior Process Engineer. He then joined Saudi Aramco in 1997 and was an integral part of the technical team responsible for the on- time initiation of the two major Hawiyah and Haradh Gas Plants that currently process more than 6 billion cubic feet (bcf) of gas per day. Adnan also directly managed the Karan and Wasit fields — two major offshore gas increment projects — with an expected total production capacity of 4.3 bcf of gas per day.

He actively participates in the Society of Petroleum Engineers (SPE) forums and conferences, and has been the keynote speaker and panelist for many such programs. Adnan's areas of interest include reservoir engineering, well test analysis, simulation modeling, reservoir characterization, hydraulic fracturing, reservoir development planning and reservoir management.

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Dr. Chris Fredd is the Stimulation Domain Manager for Schlumberger in the Middle East. His current focus is on applying a multidisciplinary approach to optimizing stimulation and completion strategies for conventional and unconventional reservoirs. Chris has over 15 years of experience with Schlumberger in a wide range of stimulation environments, including carbonates, tight gas, shale gas, and coalbed methane. He has held various positions in field operations, technology implementation, and new product development in North and South America, Russia, and the Middle East. In his previous position as Technology Center Manager, Chris commercialized 12 products related to stimulation, diversion, mircoseismic interpretation, and perforating technology, many with a specific focus on unconventional reservoirs.

He received his B.S. degree from Clarkson University, Potsdam, NY, and M.S. and Ph.D. degrees from the University of Michigan, Ann Arbor, MI, all in Chemical Engineering.

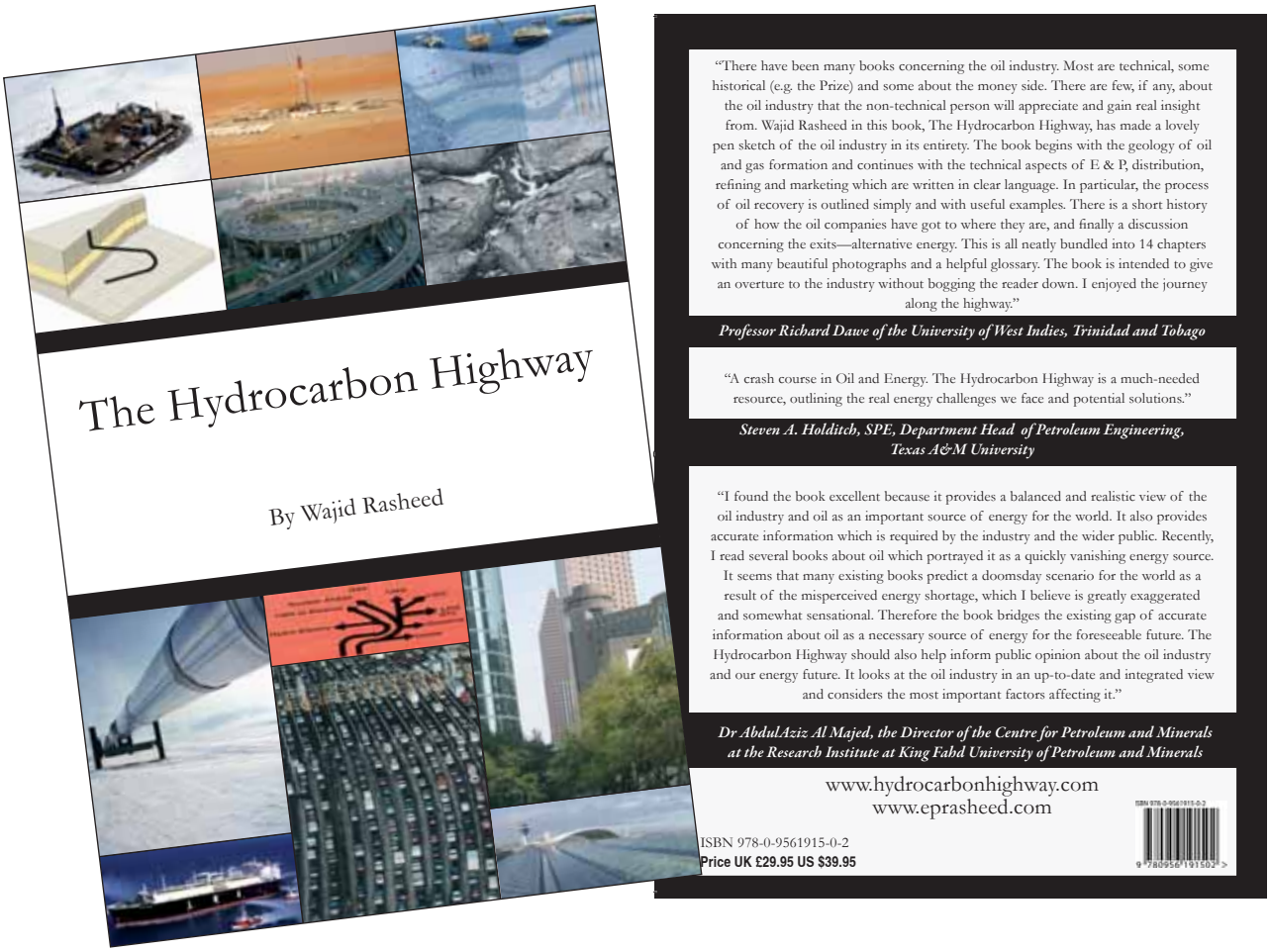
Chris holds 15 patents and has authored or coauthored almost 30 publications in the areas of matrix acidizing, fracture acidizing, hydraulic fracture conductivity, and unconventional reservoir stimulation.

Dr. M. Nihat Gurmen is a Technical Manager at Schlumberger for the Arabian Market covering Saudi Arabia, Kuwait and Bahrain. Based in al- Khobar, Saudi Arabia, he is a company Subject Matter Expert for stimulation products, fluids and services. Nihat started his Schlumberger career in the Client Support Laboratory in Sugar Land, TX, in 2004. In his next assignment, Nihat transferred to Alice, a field location in South Texas, as the District Technical Engineer. In his current role in the Arabian Market, Nihat ensures that correct technologies are applied in stimulation operations and introduces new products and services as necessary.

Nihat received his B.S. degree in Chemical Engineering from Bogazici University, Istanbul, Turkey, and earned a Ph.D. degree from the University of South Florida, Tampa, FL. He was a postdoctoral fellow at the University of Michigan, Ann Arbor, MI, in the Fogler Research Group.

Nihat is an active member of the Society of Petroleum Engineers (SPE) and coauthor of various journal, SPE and patent publications.

Renewable Energy



In this chapter we consider renewable energy sources to identify what can effectively reduce oil and gas demand, not just theoretically, but in an environmentally friendly and cost-effective way[1]. But first, what of global warming and carbon emissions?

Modern economic growth and consumption has been concentrated in Western nations with oil, gas and coal providing most of the world's marketed energy; however, things are changing. Through carbon emissions capping, some Western countries have in fact limited the use of fossil fuels. Through outsourcing, some Western countries have also de-industrialised. The new growth economies are the 'BRICs' (Brazil, Russia, India and China) whose industries and populations need more energy and resist capping.*

Against the backdrop of global warming and resource scarcity though, how can 'uncapped' consumption be sustained?

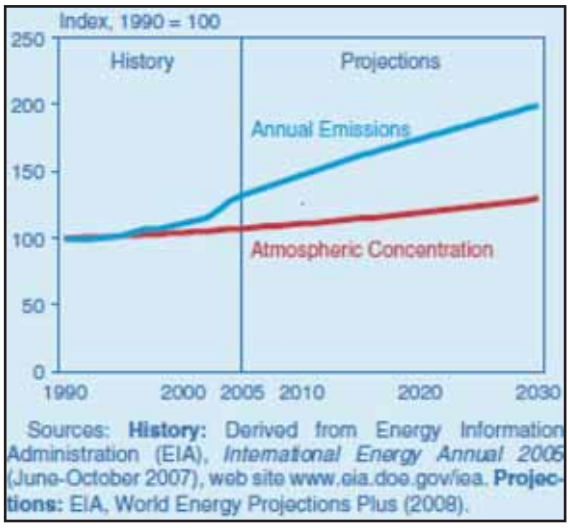


Figure 1 - Growth in Carbon Dioxide Emissions 1990-2030 (Source US EIA)

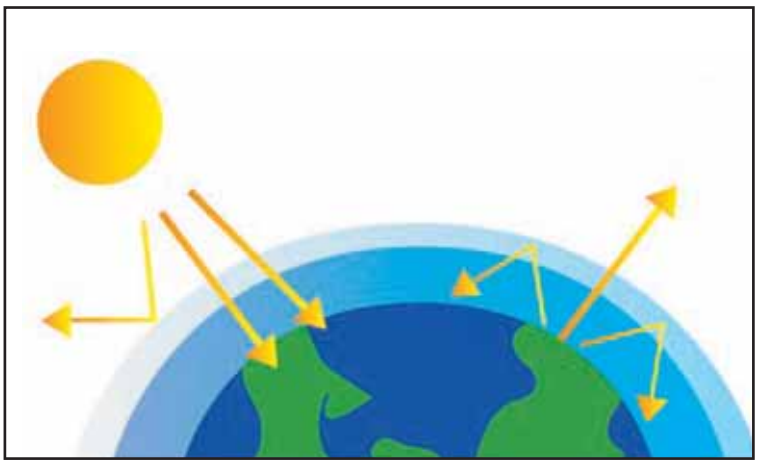


Figure 2 - Heat From the Sun is Trapped by the Gases in our Atmosphere

Global Warming

Since the 18th century and the Industrial Revolution, the temperature of the earth's lower atmosphere has been rising. Through 'the greenhouse effect', this has led to an alteration of the delicately balanced global climate system which is gradually being warmed. The greenhouse effect is so termed because levels of certain gases in the atmosphere have increased which means that more heat is retained on the earth[1].

In normal atmospheric conditions, sunlight reaches the earth passing through a layer of gases such as water vapour, carbon dioxide (CO_2), methane (CH_4), nitrous oxide (N_2O), and ozone. Here, infrared radiation reflects off the earth's surface but does not pass through the thermal layer as part of it is trapped to keep temperatures suitable to life, about 60°F (16°C). If it were not for this heat trap, the average temperature of the earth would be below freezing. The rapid industrialisation of the 18th century fuelled the demand for agriculture, land development and transport. As more fossil fuels such as coal were burned and as forests were cleared for development, ever greater quantities of Greenhouse Gases (GHG) were produced. Other types of gases such as chlorofluorocarbons (CFCs) also led to rising temperatures. Consequently, this resulted in more heat being trapped and rising air and sea temperatures[2,3,4].

Since the Industrial Revolution, volumes of CO_2 in the atmosphere have increased from 270 parts per million (ppm) to 370 ppm. This affects the natural CO_2 cycle that takes place between the atmosphere, oceans and forests. As greater quantities of CO_2 are generated, this leads to excessive loading of the natural cycle and a decreased ability of the earth's natural mechanisms

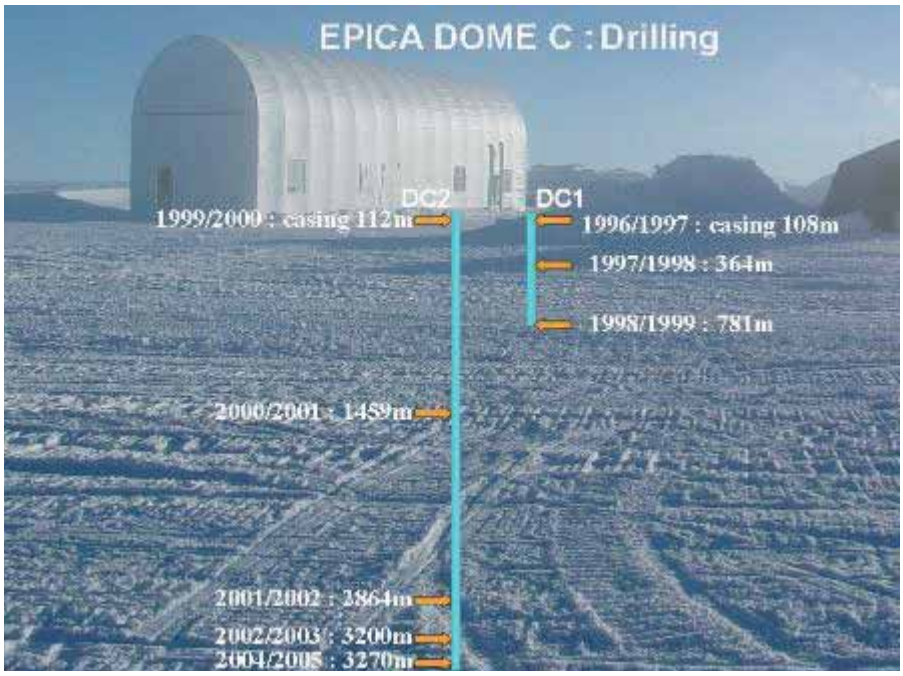


Figure 3 - EPICA

Figure 4 - Polar Ice Caps

(ocean and forests) to absorb CO_2. This gas, CO_2, has the greatest effect of GHGs and projections show that emissions will continue to grow. For CO_2 emissions to stabilise at 550 ppm, there would have to be a major reduction in the emissions complemented by new energy technologies that do not produce CO_2 at all; however, more than 80 per cent of today's energy demands are met by fossil fuels, which make replacement even more challenging.

Scientists have also started tracking changes in the polar ice caps. Since 1999, researchers working with the European Project for Ice Coring in Antarctica (EPICA) have drilled over 9,842 ft (3,000 m) into the Dome C ice, which corresponds to a geological timeline dating back nearly a million years. Over time, solids and fluids are trapped in the ice, and these provide insight into the atmospheric mixture of gases present across the timeline[5].

Researchers have found that CO_2 is now about 30 per cent higher than at any time, and methane 130 per cent higher. The rates of increase are absolutely exceptional: for CO_2, this is 200 times faster than at any time in the last 650,000 years.

Antarctic Climate Record

Some projected long-term results of global warming include: the melting of polar ice caps, a rise in sea level and coastal encroachment; the extinction of species as habitats disappear; higher intensity tropical storms; and, an increased incidence of tropical diseases. The

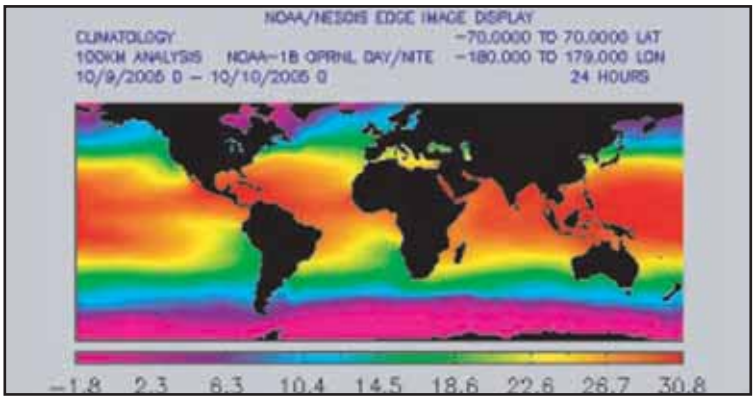


Figure 5 - Global Sea Surface Temperature Chart. Courtesy of the US National Oceanic and Atmospheric Administration (NOAA)

Polar Research Institute has been conducting studies on physical glaciology and has noted that over the past 50 years the Antarctic and Greenland ice sheets are thinning near the coast due to accelerating glaciers and increased melting. Both are thickening inland due to increased snowfall. Overall, both sheets are close to balance, i.e. the snowfall gains are comparable to the coastal losses. This is leading to a rise in sea level. At present, the best estimate is that Antarctica and Greenland combined contribute 0.2 mm per year of the 1.8 mm per year global sea level rise[6,7,8].

Several polar ice cap trends have been identified, notably in the West Antarctic, where the ice sheet is losing ice mass because the glaciers are flowing too quickly, most likely due to warm ocean waters at their termini, and that Arctic sea ice area and volume have both decreased over the past 50 years or so.

Temperature's Up

Scientists keep track of global temperatures by registering air and sea temperatures. According to US environmental body figures, the global average temperature of the air at the earth's surface has warmed between 0.5°F and 1°F (0.3°C and 0.6°C) since the late-nineteenth century, while atmospheric temperature has risen 1.1°F (0.6°C), and sea level has risen several inches[9].

Little Boy

First noticed by fishermen in 1992, 'El Niño', which in Spanish means 'Little Boy' or the 'Christ-child', describes the arrival of a warm weather event coinciding with Christmas. La Niña means 'Little Girl' and is used to describe a cold weather event.

El Niño is an alteration to the ocean-atmosphere system, which starts in the tropical Pacific but has global repercussions. These include greater rainfall and flooding across the southern US and in Peru to drought and bushfires in the Western Pacific.

El Niño can be seen in sea surface temperatures in the equatorial Pacific Ocean, such as those shown in Figure 4, which were made from the National Oceanographic and Atmospheric Administration's (NOAA) array of moored buoys[10].

Kyoto

In order to combat global warming, the UN held a meeting in Kyoto, Japan, in 1997. This resulted in an international agreement to reduce emissions of GHGs by industrialised nations. Not all industrial countries, however, immediately signed or ratified the accord. In 2001, the US government announced that it would abandon the Kyoto Protocol. At the time, this was considered a major setback as the US generates 25 per cent of global GHGs. US President Barack Obama has already signalled a policy shift to ensure carbon emissions are reduced at the federal and state level. 125 other governments agreed to a binding international treaty which runs from 2005 to 2012. Further to this, many individual US states have committed to respecting Kyoto emissions levels at a local level[11].

Deep divisions exist as to what should occur post-Kyoto. The main objective will likely be to extend the treaty to include countries that have not currently signed such as the US, Australia and Russia. A major stumbling block is the exemption of so-called developing countries such as Brazil, China and India from Kyoto targets. These

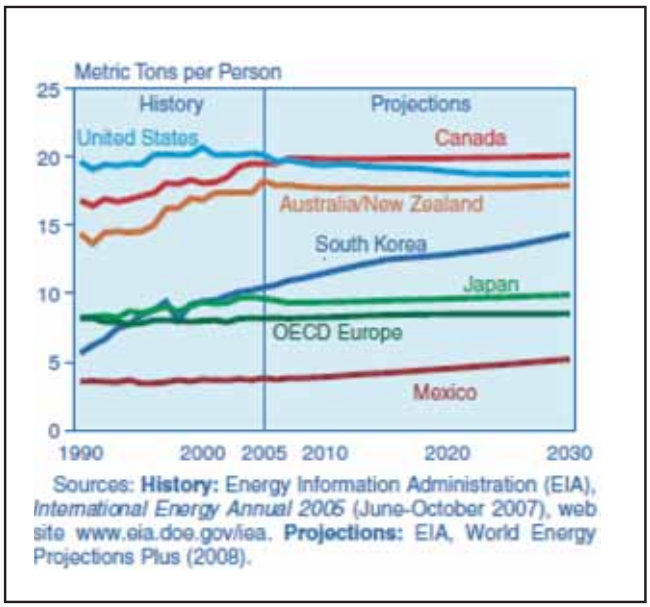


Figure 6 - Figure OECD Carbon Dioxide Emissions per Capita (Source US EIA)

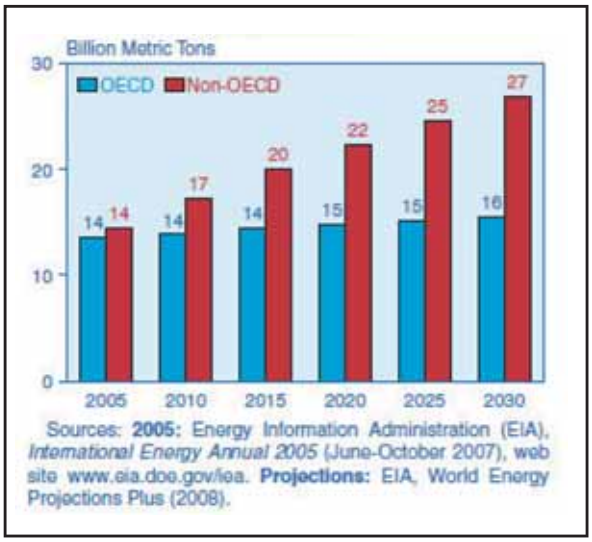


Figure 7 - World Energy Related Carbon Dioxide Emissions (Source US EIA)

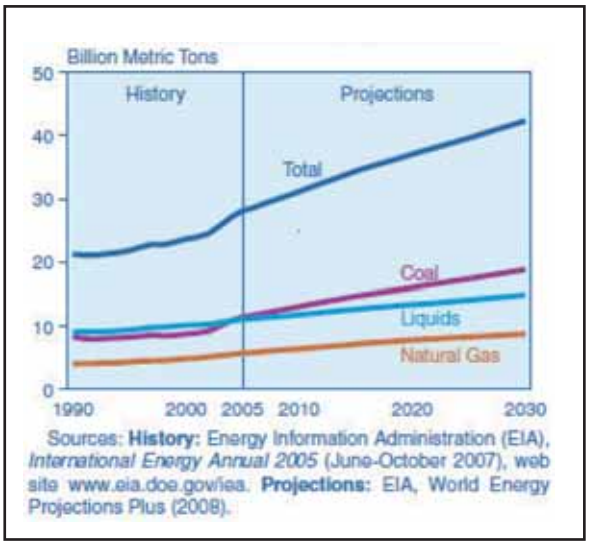


Figure 8 - Figure World Energy Related Carbon Dioxide Emissions by Fuel Type (Source US EIA)

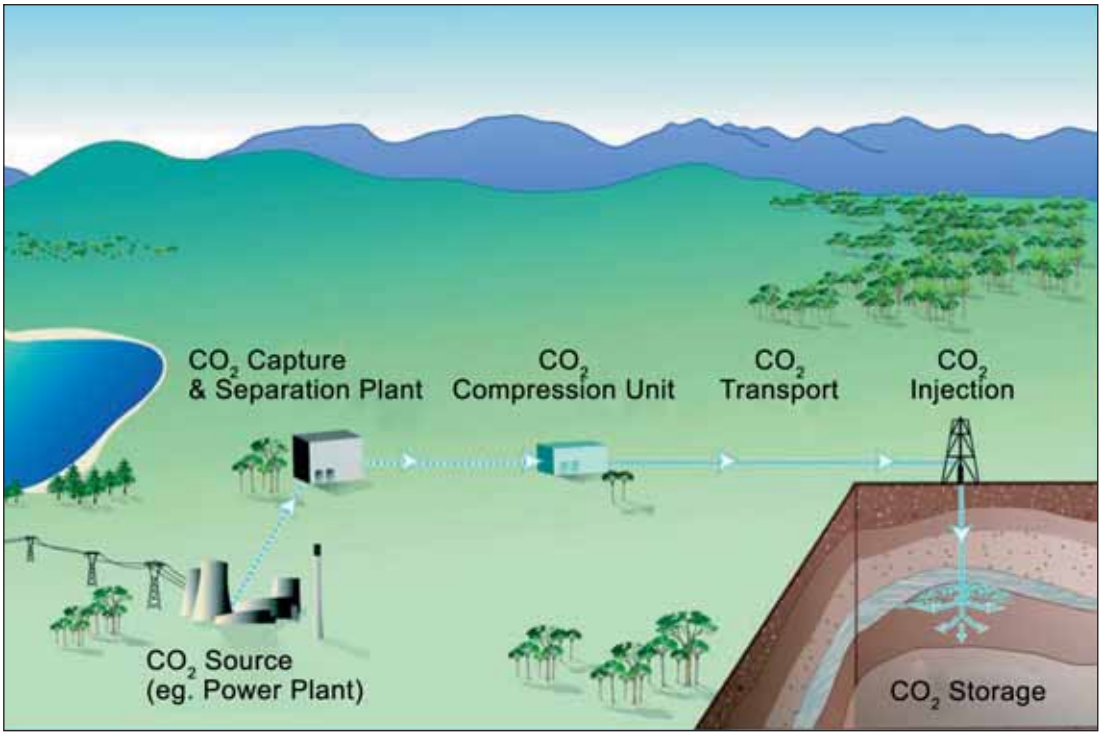


Figure 9 - Geologic Storage for Underground Carbon Capture and Storage (CCS) (Source: CO2CRC)

countries have argued that Western development was responsible for much of the CO_2 emissions and this also led to these countries gaining developed status. The argument continues that applying CO_2 emission targets to developing countries would then hinder their progress. The counter-argument is that the location of industry makes no difference to emissions and they must be capped. Only time will tell whether consensus can be reached on this issue. The arguments and debates continue.

Contributors to Climate Change

It is recognised that the main contributors of global warming are the burning of coal and petroleum products, deforestation which increases the amount of CO_2 in the atmosphere, the production of cement which releases CO_2 and increased livestock production which increases the volumes of methane gas released in animal waste.

Sceptics argue that the climate cannot be modelled as it is too complex. They also contend that observed climate changes may be normal fluctuations in global temperature[12].

Despite this, most leading scientists agree that part of the observed warming is the result of human activity, and that the trend for warming has to be broken. This means finding other options to CO_2 emitting products and a raft of energy initiatives.

Energy Initiatives

Plans to reduce emissions include improving road transport mileage per gallon, reforestation projects and energy efficiency in construction and public transport systems.

More ambitious plans would include replacing fossil fuels with safe alternates, improving manufacturing and operational processes that generate CO_2, replacing CFCs with safe alternates and reducing deforestation[13].

Emissions

In order to reduce GHG emissions, several initiatives have taken place. These include improved manufacturing and operational processes that would otherwise emit CO_2 and reduction of the usage of emissions when energy is generated, i.e. selecting less harmful options such as Liquefied Natural Gas (LNG) which produces less GHG as it has a lower carbon content (see Chapter 3 What's In a Wet Barrel – Hydrocarbon Types).

Carbon Capture

These types of technology have a crucial role to play in reducing CO_2 emissions. Essentially, carbon capture or sequestration prevents CO_2 being released to the atmosphere. The CO_2 is captured and injected deep into geological formations which are known to have natural traps or seals. Carbon capture plants can be located close to power stations and oil and gas production facilities. To accelerate acceptance and reduce the costs

> LNG has been a major boon for natural gas because it adds cost-effective transportability of large amounts of natural gas where pipelines are impractical, e.g. across the ocean.

of carbon capture, several carbon capture projects were launched focusing on carbon capture technologies and processes[14].

In terms of geologic storage, oil companies have already implemented CO_2 compression and injection into oil and gas reservoirs.

CO_2 is readily soluble in water and oil and miscible with gas. Where producing oil and gas reservoirs are contemplated, the injected CO_2 could be used to maintain reservoir production. On production, it would be separated from the oil, gas or water and re-injected. Such reservoirs are obvious choices as they already have a seal or cap rock in place (see Chapter 1: The Origin of Oil). In some gas producing provinces, as much as 10-15 per cent of the total gas in the reservoir is attributed to CO_2. In these cases, the CO_2 is not vented to the atmosphere, but is compressed and injected into the reservoir. CO_2 can also be injected into deep saline aquifers and unmineable coalbeds. It is estimated that large scale projects of this nature can take the equivalent of 200,000 cars off the road per year. Currently, several oil companies are involved in existing carbon capture projects, which are helping their acceptance from wider society[15].

It is now time to look at renewable energy sources starting with the array of gas technologies.

Gas Technologies

Gas has grown from being an unwanted hazard to the preferred energy for power generation. Illustrating this is the fact that Combined Cycle Gas Turbine (CCGT) technology has become the standard by which other power generation plants are measured. Here we look at the group of gas technologies – LNG, Gas to Liquids (GTL), Liquefied Petroleum Gas (LPG), Compressed Natural Gas (CNG) and gas hydrates. It is worth quickly noting that LNG and CNG are formed of naturally occurring fractions, principally methane and ethane; however, LNG is subjected to low temperatures and high-pressures to maintain its liquid state. CNG is subjected to compression alone as is LPG, which is principally composed of propane and butane[16].

LNG

LNG describes the liquid state of purified natural gas, principally methane and ethane, that has been

> Many developing countries such as Brazil, India and Pakistan have very advanced markets for LPG, with many petrol pumps offering it as a petrol (gasoline) alternative.

subjected to temperatures of -160°C (-256 °F). LNG has been a major boon for natural gas because it adds cost-effective transportability of large amounts of natural gas where pipelines are impractical, e.g. across the ocean.

Over the past decade, the LNG industry has grown significantly with the creation of new markets for what was previously deemed stranded gas, which was too remote to be linked to existing pipeline systems but can now be safely transported to market.

Typically, offloading facilities for LNG tankers require special berthing and unloading apparatus, with individual facilities varying in their handling capacities. Offloading involves the connection of unloading arms that pump the LNG onto storage tanks. These operate at atmospheric pressure and need to be especially well insulated to maintain the gas as a liquid[17].

LNG storage tanks are built with a double membrane wall using high strength steel nickel alloys to prevent heating. The outer wall membrane is made out of concrete. The revaporisation of LNG consists of thermal exchange processes which often use ambient seawater or other liquids to regasify the LNG before connection to pipelines.

LNG Markets

Comprising four main stages – E & P, liquefaction, shipping and storage and regasification – LNG projects require sizeable investments, often exceeding US $3 billion and highly specialised technical know-how. For these reasons, they are generally the preserve of majors.

The liquefaction facility is usually the highest cost-component within LNG projects.

Production, shipping, and re-gasification usually account for the remainder in roughly equal costs[18].

Process enhancements, technology advances and cost savings have reduced capital costs for liquefaction plants from US $600 per tonne of capacity in the late 1980s to about US $200 per tonne in 2001 and US $160.

LNG suppliers will sign contracts, typically 20 years, with buyers confirming the purchase before the projects go ahead. This explains why the LNG market has been the preserve of the major International Oil Companies

Figure 10 - Solar Panels at Munich Airport (Source BP)

(IOCs) and National Oil Companies (NOCs). The LNG global market is roughly divided into hemispherical lines, with the Western hemisphere consumers (the US and Europe) being supplied mainly by the Caribbean and North and West African exporters. The Eastern hemisphere countries of Japan, South Korea and Taiwan are mostly supplied by exports from Middle Eastern and Asia Pacific Rim countries.

LNG prices tend to follow a crude oil price index, but are higher in the Asia/Pacific basin than in the Atlantic Basin. In the US and Europe, LNG prices are more volatile following Henry Hub and seasonal demand fluctuations[20].

Exporting 38.48 Bm^3 in 2007, Qatar is the world's largest LNG exporter, with most of its exports split between Japan and South Korea. Qatargas is a joint venture between Qatar Petroleum, Total, Exxon Mobil and Mitsui and Marubeni. It also produces approximately 60 thousand barrels per day (bbl/d) of condensate in addition to sulphur. Qatargas operates ten purpose-built LNG vessels, each with a capacity of 135,000 cubic metres [21].

Malaysia was the world's second largest LNG exporter, providing 29.79 Bm^3 of LNG in 2007. Most of its exports went to Japan who consumed 17.65 Bm^3. The major part of Malaysia's LNG exports is handled through its Bintulu Complex in Sarawak.

Indonesia is the world's third largest LNG exporter having exported 27.74 Bm^3 of LNG in 2007. Indonesia exported 18 Bm^3 to Japan which is the world's largest importer of LNG (88.82 Bm^3 total for 2007). Most of Indonesia's gas production centres on the Arun field in Aceh, the Badak field in East Kalimantan and the Natuna D-Alpha field (the largest gas field in Southeast Asia)[22].

Algeria exported 24.67 Bm^3, most of which went to France and other European countries. Sonatrach Algeria was the world's first major LNG producer when it began exporting LNG to Britain in 1965. The first liquefaction plant in the world was commissioned at Arzew in Algeria. Hassi R'Mel is the country's largest gas field (discovered in 1956) and contributes a quarter of Algeria's total gas production. Other Algerian gas reserves are located in the south and southeastern regions of the country[23].

Nigeria exported 21.16 Bm^3 and this was mainly

Figure 11 - BP Experimental Fuel Cell Bus

imported by Spain and other European countries as well as North America[24].

Australia exported 20.24 Bm^3 and nearly all of it was imported by Japan. Most of Australia's production comes from the North West shelf[25].

Trinidad and Tobago exported 18.15 Bm^3, almost all going to the US. Trinidad's LNG started in April 1999 and now has the Atlantic LNG project in Trinidad and Tobago (BP, BG, Repsol and NGC)[26].

Russia is becoming the newest Asia/Pacific basin exporter. Its first LNG plant is under construction in Sakhalin Island off the country's east coast, with exports aimed at Japan.

Due to its position as the largest holder of gas reserves, it clearly has potential to develop its own reserves and supply growing demand.

Compressed Natural Gas (CNG)

Comprising purified natural gas (principally methane) that is pressurised at approximately 3,700 psi (255 bar) and stored in metal canisters, CNG is an efficient means of transporting fuel and fuelling transportation. CNG and LNG are both delivered to engines as low pressure vapour. LNG can be used to make CNG which is a substitute for gasoline (petrol) or diesel fuel. It is considered to be environmentally 'clean' and is made by compressing methane extracted from natural gas[27].

Liquid Petroleum Gas

LPG is a highly portable and convenient fuel, which can be liquefied at relatively low pressures and high temperatures. This means it can be stored in metal canisters without the need to maintain subzero temperatures or the infrastructure of LNG. LPG contains varying ratios of propane and butane that have been compressed to form a liquid. Propane is used in propane gas burners at 203 psi (14 bar) and as butane in cigarette lighters 29 psi (2 bar).

LPG is a widespread fuel used in transportation (buses, cars), domestic usage (heating and cooking) and power generation. Both alkanes are used as propellants in aerosol sprays too. Many developing countries such as Brazil, India and Pakistan have very advanced markets for LPG, with many petrol pumps offering it as a petrol (gasoline) alternative[28].

Gas to Liquids

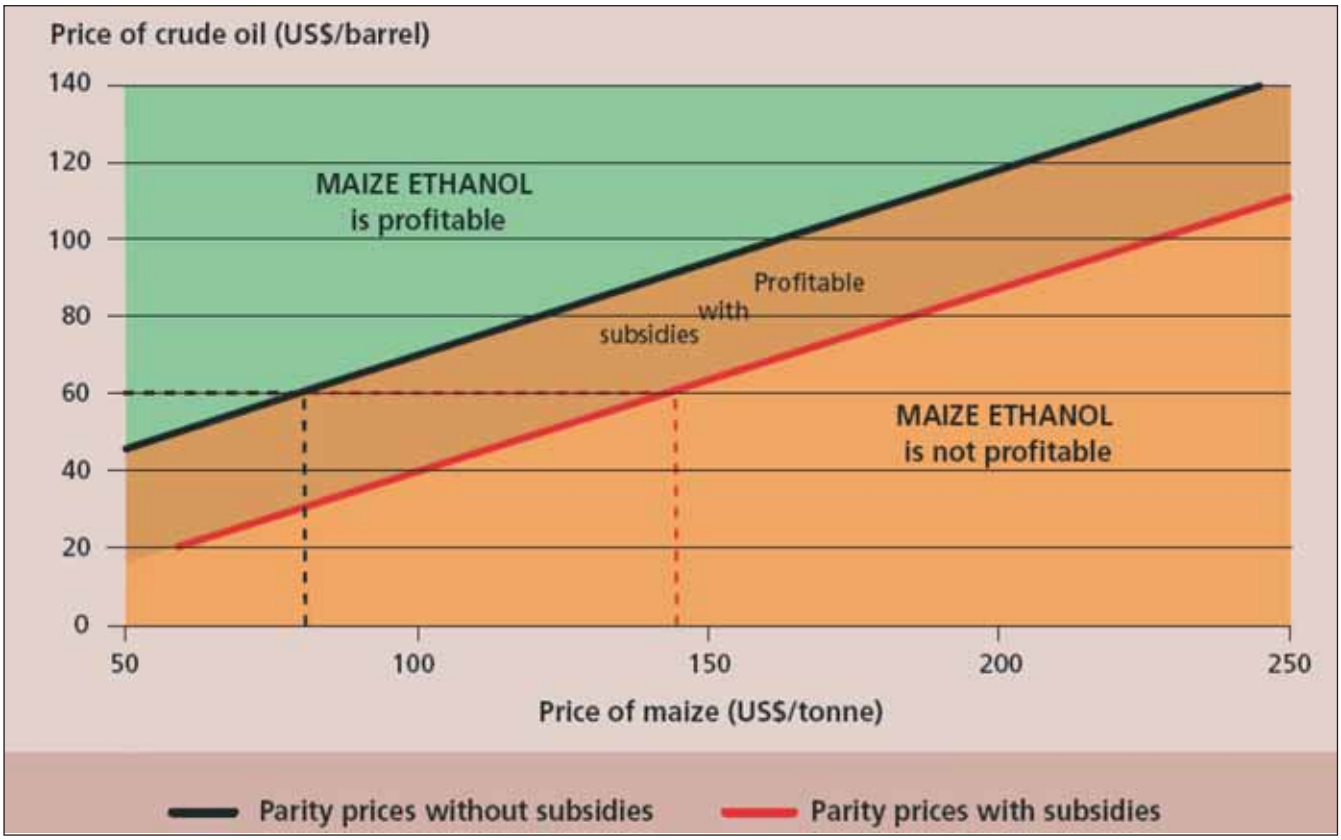


Figure 13 - Breakeven Prices for Maize Ethanol and Crude Oil with and without Subsidies (Source Petrobras)

A promising technology with a bright future, GTL is a generic term for the catalytic processes that synthetically produce petroleum fuels from gas.

The most commonly known processes are based on the Fischer-Tropsch concept where very light hydrocarbon fractions are subjected to high temperatures and pressures in the presence of a catalyst.

This partly oxidising gas is then converted into liquid and fractionated in a manner similar to conventional refining, which achieves the desired blend of refined petroleum qualities within the limits of the process configuration. Companies such as Shell have successfully trialled GTL fuel in the UK and Germany with major car manufacturers. GTL will be a key bridging application for natural gas that will reduce the demand for high-demand light automotive applications[29]. Presently, GTL is prohibitively expensive unless volumes are high. It has been put forward as a way to commercialise stranded gas (where no viable market exists for the gas) as an alternative to flaring.

Gas Hydrates

Gas or methane hydrates are ice crystals that contain high amounts of methane. They are formed when water and methane are present in freezing or below freezing temperatures. Deep and ultra-deepwater conditions are ideal for the formation of gas hydrates which are most commonly found in sedimentary beds below the ocean. Gas hydrates are thought to be created as gas migrates from source rock and is crystallised on contact with freezing seawater. Gas hydrates are of future interest as the large amounts of trapped energy may be harnessed to generate usable methane. Not surprisingly, estimates vary as to global reserves and the technology for efficiently harnessing the hydrates has not yet been developed[30].

Nuclear Power

Principally used for the generation of electricity, nuclear power harnesses nuclear reactions to release energy. Other uses include submarine jet propulsion and heat.

Although the reactor is the heart of nuclear power generation, it represents a small part of the process. Uranium ore must first be mined and then converted into a manageable form known as 'yellowcake'. It is then processed to form uranium hexafluoride which must undergo sufficient enrichment before it is configured in shape and size to make reactor-specific fuel rods. These fuel rods remain inside the reactor

Figure 14 - Biomass Plant Using Organic Waste Spain (Source Linha 10)

until approximately 3 per cent of their uranium has undergone fission at which point the rods are termed 'spent'. The spent fuel is then moved to a cooling pool for five years or more where the decaying isotopes can be safely managed. After this period, the spent fuel is radioactively cool enough to handle and it is moved to dry storage casks or reprocessed[31].

The production of spent fuel is a major drawback associated with nuclear power generation. In fact, fresh spent fuel is so radioactive that less than a minute's exposure to it will cause death. Spent nuclear fuel becomes less radioactive over time, although it is still dangerously radioactive. There are over 400 nuclear reactors generating electricity in the world[32].

The pressurised water reactor is the most widely-adopted nuclear reactor technology The ongoing improvements in technology and performance have resulted in continuing reductions in the costs of power generation from nuclear stations.

CO_2 is not released during the generation of electricity from nuclear power and it is a major factor in favour of nuclear energy. GHG emissions are very low across the whole life cycle and are comparable with the best renewables.

Globally, nuclear energy helps avoid the annual emission of over two billion tonnes of CO_2 that would otherwise be generated from fossil fuels. Nuclear generation is the largest single source of electricity in the European Union (EU). Of the 15 EU countries, those which have significant proportions of nuclear energy are consistently among those with the lowest CO_2 emissions[33].

Hydro Power

Hydro power systems generate electricity by releasing stored water in a controlled manner to drive turbines. In certain rural planning situations such as irrigation or flood barrier schemes, a hydroelectric power plant may be added with relatively low construction cost. 'Fuel' in the normal sense is not required to power hydroelectric plants which also have the advantage of zero GHG emissions. Hydroelectric plants tend to have a longer shelf-life than hydrocarbon generation plants, with some plants still generating power after a century's service. This is probably due, however, to the lack of harmful emission associated with hydroelectric plants as opposed to older hydrocarbon plants producing high emissions[34].

Figure 15 - Wind Farm Coastal Area Spain (Source Linha 10)

Low levels of rainfall or drought are the major limitation of hydro power. This can cause large reductions in power generation or may cause a complete halt. Environmental groups have stated that large hydroelectric projects can damage fluvial and marine ecosystems. The reservoirs of hydroelectric power plants in tropical regions may also produce large amounts of GHG. This is due to newly flooded and decaying plant material releasing methane once it enters the turbines[35].

Solar Power

Photovoltaic cells are most commonly seen in handheld calculators where they provide energy through the use of solar power.

Applications of the technology are used on much larger scales where they are classed as being 'on-grid' or 'off-grid' and convert daylight into conventional electricity allowing everyday appliances to be powered.

The main advantages of solar energy are self-sufficiency, reduced carbon emissions and the sale of excess energy where connection to a grid exists, given adequate generating conditions.

Solar power, however, has limitations. The energy generation may not coincide with demand and consequently, power generated during off-peak periods must be stored so that it can be used effectively during peak demand.

On-grid systems can be found in urban areas and range from applications in governmental, commercial and residential systems where large numbers (50 or more) of panels are joined to create a solar farm generating a large enough amount of solar power that can be sold back to the electricity grid wholesaler[36].

Off-grid systems are mostly found in remote locations that are unconnected to wholesale electricity grids. This includes both villages and industrial applica-tions such as in power generation or telecommunications.

The photovoltaic cell converts solar energy directly into electricity. Cells usually consist of several wafers of silicon or other semi-conducting material. The cell itself is a semiconductor diode that, depending on its configuration, can convert visible, infrared or ultraviolet light into direct current electricity.

When the cell is exposed to light, electrical charges

"Major advantages of photovoltaics include the fact that they are non-polluting, only require real estate (and a reasonably sunny climate) in order to function and rely on solar energy which is unlimited in supply."

generated in the silicon are conducted by metal contacts as direct current. Many cells are required to generate meaningful amounts of electricity and these are found in the form of glass solar panels[37].

Depending on the output required and other factors such as location, as many panels as can be configured to generate the required electrical output are required.

According to Shell, Copper Indium Diselenide or CIS refers to thin-film technology that may provide further cost savings as it is cheaper and more durable than silicon[38].

Large sets of photovoltaic cells can be connected together to form solar modules, arrays, or panels.

Major advantages of photovoltaics include the fact that they are non-polluting, only require real estate (and a reasonably sunny climate) in order to function and rely on solar energy which is unlimited in supply.

By making use of the photovoltaic effect, solar cells produce electricity. Absorbed light excites the electrons with negative electrons (-) attracted to the N-layer, and positive electrons to the (+). Once the circuit is closed, electricity is created.

Fuel Cells

Continuous electrochemical reactions form the basis for fuel cell energy. As well as offering high theoretical efficiency, fuel cells emit low or even zero levels of pollutants.

The fuel cell itself runs off hydrogen, but with the use of steam, reforming or partial oxidation can be powered by gas and GTL products. Fuel cells have the potential to be used in power generation and light automotive applications; however, the major limitation is the prohibitive costs associated with the technology.

The competitive target for fuel cells to compete with the internal combustion engine is US $50/kW. In stationary applications, a cost of US $1000/kW is seen as the long-term goal. Battery replacement can absorb very high costs per kW and lowest economic hurdle to entry. Today, prior to mass production and essentially in custom-build mode, fuel cells are somewhere in the US $2000/kW to US $20,000/kW range.

> Biogas refers to biologically produced methane which is generated from any biomass feedstock, i.e. organic waste material such as wood pulp, animal residues or municipal organic waste.

At between US $4000/kW to US $20,000/kW for stationary applications, they are well above a mature technology such as gas turbines at US $400/kW to US $600/kW. Even novel micro-turbines currently cost US $1000/kW to US $2000/kW. Mass production is seen as the solution to the high cost. In the meantime, funding from government agencies and companies interested in the technology has provided support for demonstration projects[39].

Biomass

Biomass is a catch-all term used to describe any solid, liquid or gas fuel that is derived from organic mass itself or its residues or byproducts. Each fuel type needs be distinguished if we are to understand the potential role each fuel has in replacing oil and gas demands. Liquids include 'biodiesel' that can be used in compression engines and are produced by modifying esters in vegetable seed oil. Liquids also include 'biogasoline' (ethanol) that can be used in spark engines and are produced from the fermentation of sugars. Finally, liquid fuels also include 'bioGTL' that can be used in both types of engines and are produced from GTL technology using biologically or man-made produced methane (biogas)[40].

Biogasoline

Biogasoline is the liquid biomass subset that contains ethanol, a well known alcohol fuel, but increasingly other fuels such as propanol and butanol.

Brazil is a major producer of sugarcane derived ethanol fuel, which is commonly available in roadside filling stations along with petroleum spirit and LPG. The US also produces corn-based ethanol as a complement to petroleum rather than a substitute; however, ethanol replacement of petroleum is increasing. Detractors claim that its cost is greater than any value it brings to the equation[41].

Production

Ethanol can be produced from the fermentation of sugars or the steam cracking of ethane.

In the former, juice from sugarcane, corn or other feedstock is mixed with yeast and water at just above room temperature. Enzymes in the yeast break down the sugars into ethanol and CO_2. The CO_2 is vented to stop the ethanol from oxidising and becoming ethanooic acid (vinegar). Fractional distillation increases the yield of ethanol to 'fusel oil' or anhydrous ethanol (5 per cent water by volume)[42].

> Biomass plants (also referred to as waste transformation plants) convert a potential contaminant (farmyard waste or other residues) into a marketable commodity (fertiliser).

Ethanol can also be produced by the steam cracking of ethane in the presence of a strong acid catalyst. The reversible reaction is carried out at a moderately high temperature (i.e. 300°C [572°F]) and a high-pressure (i.e. 900 psi [62 bar]). The higher temperature and catalyst speed up the reaction. Although it is a faster and more continuous process, the disadvantage of the ethane route means further demands on oil and gas[43].

On average a tonne of sugarcane renders 65 litres of ethanol. The average cost of production, including farming, transportation and distribution, was US $0.31-0.35 per litre in Brazil, with a pump price of US $0.63-0.69 per litre in mid-2006. It is striking to trace these prices since 1999. At that time, the pump price of ethanol was US $0.09. Interestingly, this is a quadrupling of price over a seven year period. It is even more striking when we correlate the prices of ethanol and oil since 1999 to mid-2006. We see there is a quadrupling of price from US $10 to US $70. As a rule of thumb, the price of ethanol per litre is a tenth of the price of a barrel of crude oil[44].

Even though the differences between low-cost sugar producers such as Thailand, Pakistan, Brazil are not prohibitive, Brazil has the infrastructure to remain the lowest cost ethanol producer.

It is highly probable that the sugarcane farming for ethanol production will increase as is illustrated by the demand/supply equation. This may have unwanted consequences and a balance will have to be struck as ethanol tends to become a cash-crop in certain replacement scenarios for gasoline; when oil prices are high, it displaces other crops[45].

Biogas

Biogas refers to biologically produced methane which is generated from any biomass feedstock, i.e. organic waste material such as wood pulp, animal residues or municipal organic waste. It is worth considering this process in detail as it can convert contaminants into commodities. Solid biomass includes the use of wood or dried animal dung for domestic cooking and heating. Liquid biomass includes animal or farming waste that has not been treated.

Methane gas is produced by bacteria during the decomposition of organic feedstock in a highly controlled process. The gas formed in this way is

> It is worth noting that the biomass process has an application in any geographical location that presents a demand for electricity, the need to treat farmyard or other organic waste such as timber residues and offers a ready supply of natural gas.

renewable and is a highly flexible form of generating gas as the feedstock can literally be any type of organic material.

The methane produced synthetically is often pure enough to pass directly through gas engines to generate direct electricity commercially or on a local scale. The biomass methane can also be used as the feedstock for the GTL process to create synthetic fuels. It is well-suited to electrical co-generation and waste treatment.

Biomass plants (also referred to as waste transformation plants) convert a potential contaminant (farmyard waste or other residues) into a marketable commodity (fertiliser).

Waste transformation plants allow the generation of electrical energy in a separate market from hydro-electric, gas turbine or nuclear based energy. Feedstocks include (but are not limited to):

- Biodegradable waste
- Sewage treatment sludge (primary or raw sludge and/or secondary sludge)
- Slaughterhouse waste
- Food waste
- Farm waste, and
- The organic component of mixed municipal waste.

Biomass plants are a sustainable clean and green energy process whose emissions and by-products (CO_2 and H_2O) are released to the atmosphere in a controlled manner. Ammonia and other by-products are re-incorporated within the fertiliser or, where required, are retrieved separately in liquid form. There is no release to the atmosphere.

It is worth noting that the biomass process has an application in any geographical location that presents a demand for electricity, the need to treat farmyard or other organic waste such as timber residues and offers a ready supply of natural gas. Locations within Canada, Brazil, Bolivia and other European countries would fit this category; however, factors such as

> In countries where natural gas supply outstrips demand (Trinidad, Bolivia and Canada), co-generation plants can be an economical way of sustaining energy development as well as meeting growing electrical energy demand.

average ambient temperature can dictate the overall energy efficiency and profitability of biomass plants. In the case of animal waste, in cold climates during the winter, energy is required to sufficiently dry the waste. Biomass plants, however, can act as a catalyst for the development of, and demand for, natural gas in separate markets from traditional consumer or industrial sectors. In countries where natural gas supply outstrips demand (Trinidad, Bolivia and Canada), co-generation plants can be an economical way of sustaining energy development as well as meeting growing electrical energy demand.

Biogas Description

A thermoelectric co-generation plant receives farmyard animal waste which is dried using natural gas fired ovens. Ducts are connected to combustion chambers enabling exhaust gases to be harnessed to drive turbines which generate electrical energy. Excess exhaust gases and heat generated by the system are regulated through a calorific control process and is used to dry the animal waste. After drying in the ovens, the waste has lost a high percentage of its water content and is characterised as stable—it will not ferment nor liberate toxic fumes. Effectively, this means that it has been converted into commercial fertiliser that meets environmental and legal requirements.

The process offers six major advantages:

- Generation of electrical energy
- Stimulation of natural gas demand
- Conversion of a potential contaminant into fertiliser
- Sustainability
- Controlled emissions, and
- Scalability (up and down) of plant size to meet market specific conditions.

This process is increasingly attractive as it meets energy needs in an environmentally friendly manner.

Waste Processing

This case study presents a co-generation plant based on technical considerations and Return on Investment

(ROI) calculations. The quantity of waste that can be collected from various farms in the area is approximately 350,000 kg per day with a humidity varying between 65 per cent and 70 per cent. For the purposes of this study, 216,000 kg of waste would be treated per day. Final humidity is calculated to be approximately 20 per cent, a figure recognised by the waste treatment industry as the standard for compost or fertilisers. This plant runs for 8,000 hours per year due to the demand created by non-stop farmyard waste production[46].

The electrical and thermal co-generation plant uses natural gas-driven motors to dry waste from untreated levels of humidity (67.5 per cent to 20 per cent). The make and number of motors, however, can be modified to meet market specific needs. The gases liberated during the drying process are used as exhaust gases to drive engines which generate electricity. The dried waste is converted into marketable fertiliser for which there is ample demand.

Co-Generation Plant

The co-generation plant consists of the following equipment:

1. Natural gas engines
2. Waste pre-treatment system to condition waste before it is fed to the drying ovens. This maintains humidity and pH at controlled levels
3. Thermal drying ovens utilising the energy released from the exhaust gases and the water refrigeration units
4. Gas filters to absorb volatile particles and ammonium
5. Engine exhaust gas conduits and chimneys
6. Thermal exchange units to dissipate residual heat in the system, air coolant and cooling towers to dissipate unused residual heat from the thermal exchange units
7. Water circulation pumps
8. Electrical equipment (engine control unit, transformers etc. guaranteeing power output)
9. System and instrumentation management and control, as well as an anti-incendiary system
10. Ventilation and climate control of all areas

Not only is a potential contaminant treated and converted into a valuable commodity, but electrical energy is generated in a renewable process. Additionally, demand for natural gas is stimulated. This is important as gas reserves are increasingly being seen as a mobile commodity due to the liquefaction and storage innovations.

Wind Power

Using a combination of turbines and nacelles, wind energy can be used to create mechanical and electrical energy. Wind power has the major advantage of zero emissions, but has output and aesthetic limitations. Consequently, wind power generation needs power storage capacity so off-peak power generation can be used effectively during peak demand. Such power generation types are generally more expensive per unit of electricity generated than base-load generators, so electricity suppliers prefer to minimise their use. Despite this increasing numbers of wind farms and standalone wind turbines are being set up by companies and individuals seeking their benefits.

Considered more appealing due to their unobtrusive offshore location, these wind turbines can be configured on a larger scale than their onshore counterparts. Offshore construction is, however, more complicated and expensive and such installations must withstand harsh conditions and subsea cables must be installed to transfer electricity.

Offshore turbines are also considered more efficient as higher average wind speeds are recorded over water, which offers less drag than land. Several European countries such as Spain and Denmark have implemented wind generation[47].

This review of renewable technologies helps us understand how easily or not oil can be replaced. In turn, this is the basis of the energy demand and supply equation. In the final chapter, this complex inter-play is unravelled so that we can envision how oil and gas applications may co-exist with other energy supplies. Can we actually live in a world that is not so dependent on oil and gas resources? Can we use other sources of energy to give us the same kind of lifestyles we have become accustomed to? What about our future generations – will they be leading a 'greener' life with less hydrocarbon use? How will that be possible?

It is now time to think about exits from the hydrocarbon highway – exits that will still allow us to meet energy demand but in a new, more environmentally friendly manner.

Can we turn away from hydrocarbons? One day of course, oil usage will decline. Yet, before that happens, the industry will continue to find, develop and produce oil more effectively. Why? The answer is simple – to provide an essential resource to mankind that will remain the preferred source of energy for the near future. To put it simply, despite oil price fluctuations, the demand for oil will continue to grow. The next

chapter helps break down where all this demand comes from and the mass of products and processes that are dependent on oil.

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41. Despite this ethanol is increasing market share.

42. The fuel standard is higher and can be 99% reached by denaturing.

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