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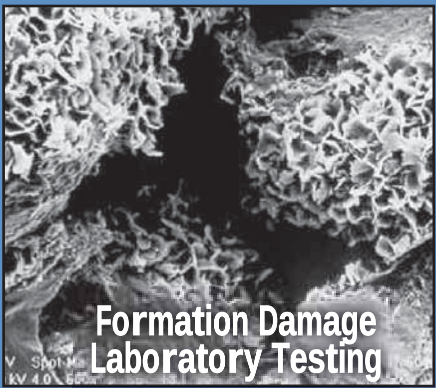


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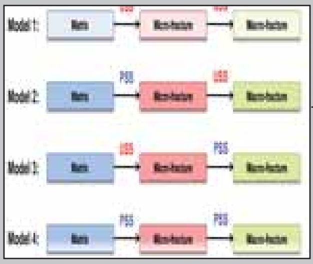

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A New Petrobras

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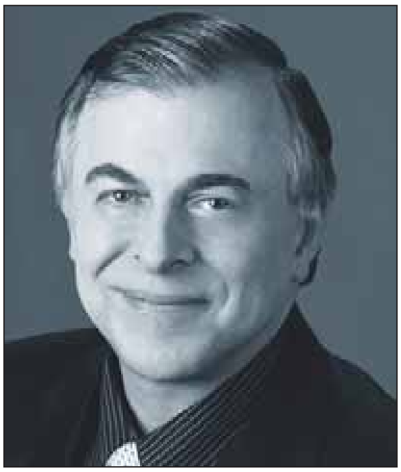
Petrobras Downstream director Paulo Roberto Costa explains how the company is going to increase its refining capacity to process the oil extracted from the pre-salt province and strengthen its activities in the Petrochemicals area to go from being an importer to being an exporter of oil and oil products.

As the Petrobras Downstream director, the engineer Paulo Roberto Costa is leading processes that are going to alter the profile of the company considerably. Among them, there is the enlargement of the Petrobras refining park because of the company's increase in oil production, especially due to the beginning of production in the pre-salt area. Also, there is the expansion of basic petrochemicals production and operations in the second generation, in synergy with other businesses in the Petrobras System. To achieve these aims, five new refineries will enter into operation by 2015, and Petrobras will strengthen its presence in the Petrochemicals area, increasing its competitiveness in Brazil and abroad.



Paulo Roberto Costa – Petrobras Downstream Director.

Brazil Oil and Gas: What is the present volume of oil refined by Petrobras relative to that produced?

Paulo Roberto Costa: The peak of Petrobras' refining capacity is around 1.9 million barrels of oil per day, considering that all the refineries are operating at maximum potential. However, as there are shutdowns, planned or not, the average is 1.8 million barrels per day. The Petrobras production is two million barrels per day in Brazil. The demand from the Brazilian market including diesel, gasoline, liquefied petroleum gas (LPG), jet fuel, naphtha, coke, and bunker, has been 1.8 million, a quantity that decreased by 1.2% from 2008 to 2009, due to the world economic crisis. The excess of oil is exported. Our refining capacity is therefore very close to the demand and is below production. Considering the expectation for growth in the Brazilian GDP of around 4.5% in the coming years, which will generate higher consumption of oil products, and the estimation of total Petrobras production at 3.5 million barrels of oil equivalent per day in 2015 and 5.7 million in 2020, due to the production from the fields in the pre-salt area, it will be necessary to increase our refining capacity. It would not be interesting for our balance of payments to export oil, with lower added value, because we could not process it here, and import oil products that are more expensive. We therefore decided to expand our refining capacity by 1.2 million barrels per day by 2015. In this way, we will be able to serve the Brazilian market. We are also aiming at the external market, through the exportation of excellent quality diesel and oil products produced in the Abreu e Lima, Premium I, and Premium II refineries.

Brazil Oil and Gas: The Abreu e Lima Refinery will begin operations in 2012. What will its role be?

Paulo Roberto Costa: The Abreu e Lima Refinery, which is under construction in Pernambuco, will pro-


J. Valpereiro / Petrobras Image Bank

Petrobras is going to increase its refining capacity by 1.2 million barrels per day.

cess 230,000 barrels of Brazilian and Venezuelan heavy oil per day, with the production of diesel being the focus of this unit to meet the growing demand in the Northeast region of Brazil. The target is to produce diesel with 10 parts of sulfur per million, with low sulfur content and excellent quality, for engines with Euro 5 technology. This diesel, presently sold in the European market and in the United States, could be commercialized by Petrobras in both markets. In Brazil, it will be destined for engines that are not yet available, but will be manufactured in the country within three years. The annual production forecast for the refinery is around 814,000 m^3 of petrochemical naphtha, 322,000 tons of LPG, 8.8 million tons of diesel, and 1.4 million tons of petroleum coke.

Brazil Oil and Gas: In technological terms, the refinery will be a mark for Petrobras, because it will be the company's, and Brazil's, first unit to process 100% heavy oil, won't it?

Paulo Roberto Costa: It's true. The other Petrobras refining units and the other refining units in Brazil still depend on mixing light oil with heavy oil, which is called blending, for the production of oil products. The advantage of the Abreu e Lima Refinery will be reflected in economic benefits for Petrobras, given that the refinery will process a type of oil that is cheaper in the international market and sell products with greater added value and therefore more profit.

Brazil Oil and Gas: The Premium I Refinery is planned to be Petrobras' largest. What contribution will it make to the company's strategy?

Paulo Roberto Costa: The refinery, which is under construction in Maranhão, will refine a third of all the Brazilian oil currently produced by Petrobras. It will have a marine terminal and pipeline right of way to receive oil and export oil products with a low sulfur content and excellent quality.

The unit will supply the internal market and will also be able to export the excess of diesel to other markets. It will have the capacity to process 600,000 barrels of oil per day. It will begin operating in two phases: the first is forecast for 2013, when it will process 300,000 barrels of oil per day; the second is planned for 2015, when it will operate at full capacity.

Brazil Oil and Gas: The Premium II Refinery is to be constructed in Ceará. Will it have its production directed essentially towards the external market?

Paulo Roberto Costa: Yes. In that state, we will construct in the Pecém Port and Industrial Complex a refinery that will produce diesel oil of 10 ppm, jet oil, naphtha, LPG, and coke. The unit will begin operations in two phases;

Paulo Rodrigues / Petrobras Image Bank

The target is to produce diesel with 10 parts per million of sulfur.

the first, with the capacity to process 150,000 barrels of oil per day, and the second with equal refining capacity. The original idea is to begin opera tions in the first phase in 2013 and to begin the second phase, at full capacity, in 2015.

Brazil Oil and Gas: Are the locations of the Abreu e Lima, Premium I and Premium II refineries in the Northeast region of Brazil more advantageous for Petrobras business?

Paulo Roberto Costa: Without a doubt. Geographically closer to the sea and to ports than the Petrobras refineries situated in the Southeast region, these new refineries will provide a reduction in freight costs for the exportation of oil products. Accordingly, the prices of Petrobras products will become more competitive in the external markets and this will result in a competitive advantage for the company.

Brazil Oil and Gas: The Clara Camarão Refinery, situated in the Guamaré complex in Rio Grande do Norte, is another of the Petrobras units destined to raise the refining capacity of the company. How is this going to happen?

Paulo Roberto Costa: The refinery presently processes 30,000 barrels of oil per day produced from the Rio Grande do Norte onshore and offshore fields. But it will be expanded. It will have a gasoline production unit, nine tanks, 23 km of pipelines (19.6 km of which are subsea), and a new buoy set that will enable the mooring of ships up to 50,000 tons. Once the infrastructure and expansion work is concluded, an investment of US$ 215 million, the unit will produce 21,000 m^3 of gasoline, 45,000 m^3 of diesel, 7,500 m^3 of jet fuel, 11,700 m^3 of LPG, and 3,000 m^3 of petrochemical naphtha per month, making the state of Rio Grande do Norte self-sufficient in oil products.


Geraldo Falcão / Petrobras Image Bank

The Pecém Marine Terminal.


Geraldo Falcão / Petrobras Image Bank

Rio Grande do Norte.


Rogério Reis / Petrobras Image Bank

Petrobras is preparing to become more competitive globally.

Brazil Oil and Gas: Finally, so far as refining is concerned, the Petrochemical Complex of Rio de Janeiro, which begins operations in 2012, will be the fifth Petrobras unit to fulfill a relevant role in increasing the company's refining park. How will it contribute?

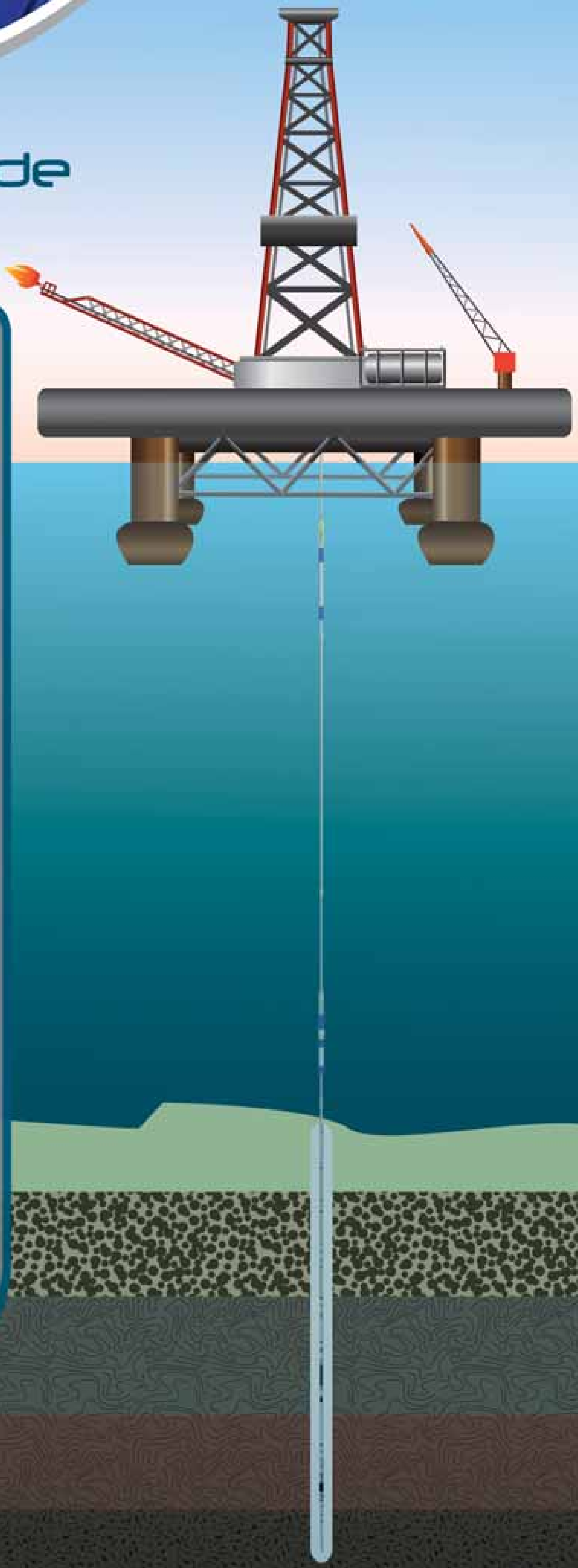
Paulo Roberto Costa: COMPERJ will increase the Brazilian ca pacity to refine heavy oil from the Campos Basin, adding value to this oil, which would yield less to Petrobras if it were sold abroad than the commercialization of oil products. The complex will also reduce the Brazilian imports of petrochemical products, generating annual savings for Brazil of around US$ 2 billion in foreign currency. In addition, it will supply the internal and external markets with second generation products. Initially, the unit will process 150,000 barrels per day of heavy oil, but it will be able to double its production capacity and become more competitive. The complex will have a refining unit, a first generation or basic petrochemical unit, for the production of basic petrochemical products, such as ethylene and propylene. It will include a group of second generation units that will transform basic products into petrochemical products such as styrene, ethylene- glycol, polyethylene, polypropylene, and PTA. In addition, it will have a utilities center, responsible for the supply of water steam, and electricity for the entire complex. Third generation or manufacturing industries should be installed in the surrounding area.

Brazil Oil and Gas: Will the increase in the Petrobras refining capacity make Brazil self-sufficient in oil products between 2012 and 2013?

Paulo Roberto Costa: Yes. Petrobras presently imports LPG, jet fuel, diesel, and naphtha in addition to around 300,000 bpd of light oil, which are used for manufacturing Petrobras lubricants in the REDUC refinery in Rio de Janeiro and for blending with heavy oil for processing in several refineries in the Petrobras System. On the other hand, the company exports gasoline, fuel oil, and bunker. Now that the production has begun in the fields in the pre-salt area, the volume produced allied to the increase in refining capacity will make Brazil self-sufficient in oil products between 2012 and 2013. Petrobras will change its profile. It will cease to be an importer and become an exporter of oil and oil products.

Brazil Oil and Gas: In parallel, Petrobras has progressively strengthened its presence in the petrochemical area. It recently increased its stake in the capital of Braskem, which acquired the shares of Quattor previously detained by Unipar, and became the largest petrochemical company in the Americas. What are Petrobras' intentions here?

Paulo Roberto Costa: Oil companies in general have a strong presence in the petrochemical area, because what they generate in the refining of oil serves as raw material for the petrochemical industry, especially for the production of polypropylene and polyethylene resins. For this reason, refining and petrochemical operations are integrated. In 2004, Petrobras began to restructure the petrochemical sector. It bought the Ipiranga Group jointly with Braskem and the Ultra Group. It acquired Suzano Petrochemicals alone. It formed Quattor Petroquímica S.A. with Unipar. It moved from an unimportant minority stakeholder to a relevant stakeholder in Braskem and increased its participation in both the capital and the management of the company. Now Braskem has bought Quattor, becoming the eighth largest petrochemical company in the world and the largest in the Americas with 26 petrochemical plants among its assets. We still want to elevate it to the fifth in the world within five or so years. The target of Petrobras is to generate stronger companies that are integrated, with greater synergy between refining and petrochemicals, so that it becomes more competitive in the global market, as well as efficient, technologically capable, with scale gains and a greater capacity for investment and growth. In this way, the company will leverage the development of Brazil, increase its international presence, and be on the right road to becoming one of the largest integrated energy companies in the world, as foreseen in its Business Plan.



Pioneering in the Gulf

Reprinted with kind permission from Petrobras Magazine.

Petrobras takes the first FPSO and widely recognized technologies in which it has know-how to the U.S. sector of the Gulf of Mexico and alters the modus operandi in the region.

The largest operator of Floating Production, Storage, and Offloading oil systems (FPSOs) in the world, with almost three decades of experience, and also internationally renowned for the technology employed in association with its platform ships, Petrobras is exporting this know-how on a pioneering basis to the oil industry shopwindow of the world. It is taking its expertise to the U.S. sector of the Gulf of Mexico, where the largest companies in the energy industry are working, and where the company is going to explore for and produce oil and gas in the Cascade and Chinook fields. Accordingly, it will become the first operator in the region to have an FPSO, a disconnectable buoyant turret mooring system, self-sustainable hybrid risers, multiphase submarine pumping, and oil transportation using shuttle tankers. This will completely change the methods of operating presently being used there.

The use of FPSO units in the region had not previously been allowed by the regulatory agency for activities related to oil, gas, and mineral resources – the Mineral Management Service (MMS) – because all of the active oil fields were connected to the land by pipelines. As the Cascade and Chinook fields, which are 24km apart and some 250km off the Louisiana coast, are situated in ultra-deep waters, they will be developed simultaneously. Since no constructed oil pipelines are yet available at this distance and such depth, the arrangement is justified. To build such an infrastructure would demand more time and money, which would not be advantageous in the beginning.

The FPSO that Petrobras will operate in the Gulf waters, named BW Pioneer, is 241m long, 42m wide and 20.4m high. It is capable of processing 80,000 barrels of oil per day and will be installed in the first half of 2010, at a water depth of 2,500m, a record for any type of platform. "The unit will be used in the first phase of developing the Cascade and Chinook fields, in which the objective will be to analyze the performance of the reservoirs so as to optimize the subsequent phases. Petrobras will be the operator in both fields, which are situated in the Walker Ridge area," says the Petrobras America vice-president of Upstream, Gustavo Amaral.

The platform ship is equipped with an internal mooring system using a disconnectable turret buoy. This makes the equipment ideal for the region, where there are often very strong currents and winds, gigantic waves, and hurricanes. For example, in the 2009 hurricane season, Hurricane Ida caused the suspension of 29.6% of the oil production and 27.5% of the natural gas extraction.

Petrobras America Archives

The first FPSO installed in the US sector of the Gulf of Mexico.

Petrobras America Archives

Transportation of the (yellow) turret buoy.

In 2008, Hurricane Ike devastated at least 49 platforms offshore. And in 2005, Hurricane Katrina destroyed 44 platforms in the Gulf, while Hurricane Rita damaged a further 64. In the Gulf as a whole, there are thousands of platforms in operation.

Within this context, the disconnectable turret buoy will function as a piece of safety equipment. "The equipment will enable the FPSO to revolve around an axis to position itself according to the most favorable current and wind conditions. Because it is disconnectable, with risers*, umbilicals**, and systems for monitoring the floating unit coupled to the buoy, it will become possible, as a hurricane approaches, to disconnect the platform ship from the wells to which it is connected so that it can navigate to calmer waters, where it can remain in safety, returning to the working location when the situation is normalized. The rest of the structure will remain below sea level, protected against inclement weather. Accordingly, it will be possible to ensure the safety of the personnel on board, preserve the equipment, and reduce interruptions in operations," explains the manager of Walker Ridge production assets, César Palagi.

The FPSO will remain connected to two wells in the Cascade field and one in the Chinook field during the first phase of the development of the fields. In the second phase, more wells from both fields will be connected to the floating unit.

Regarding the technologies exported to the Gulf, an external mooring system using the more elastic polyester cables will cushion the movements of the FPSO, an advantageous solution in an area subject to stormy weather. It will also avoid the weight of critical loads on the floating unit.

Two subsea electric pumping systems will be used to lift the production from the seabed to the FPSO. This solution will bring logistical and economic advantages. "Since the pumps will be placed outside the wells, repairs or possible exchanges may be made more easily. Since it will no longer be necessary to intervene in the wells, the production interruption time will be less, as will the costs, even though the initial investment in installing pumps outside the wells is greater than installing them inside," says Palagi.

The tubing adopted to transport the oil and gas from the outflow lines to the FPSO and the gas from the unit to the export gas pipeline will be self-sustainable hybrid risers. In this system, rigid vertical risers suspended by floating elements are extended from the seabed to around 100m below sea level, with the connection to the FPSO being made through flexible lines. In all, five risers will be used in the first phase of the development of the Cascade and Chinook fields. "The use of these risers will reduce the weight in the mooring system of the FPSO and ensure the unit greater security in the case of hurricanes," justifies Palagi.

Petrobras America Archives

Hoisting the components of the subsea electrical pump.

When dealing with very deep waters and high pressures, conditions that could lead to the cooling of fluids and the formation of hydrates or solid elements in the pipelines transporting hydrocarbons, the production lines utilized will be the pipe-in pipe design. They will be among the deepest in the world. "We are dealing with a system in which the lines transporting the fluids are inserted into other lines and the internal lines are thermally insulated with material developed by nanotechnology and put around the ring that connects one tube to another. With this technology, it is possible to operate without constant interruptions despite the cooling of the lines," he goes on to clarify

As for the shuttle tankers, they will constitute the best alternative for the outflow of the oil produced in the Cascade and Chinook fields, far from the coast of the Gulf, where it will be marketed in the USA to be refined. After all, in the event of hurricanes, the measure will prevent damage to the infrastructure of oil pipelines.

From what can be seen, it is possible to conclude that the project of developing the Cascade and Chinook fields marks history for Petrobras. "For the first time, the company has the opportunity to take out of Brazil its offshore technology that has been developed and applied successfully for decades. The result of doing this in the U.S. Sector of the Gulf of Mexico will be to give higher visibility for Petrobras, to crown its strategy in the region, and to consolidate its position in the USA," concludes the president of Petrobras America, José Orlando Melo de Azevedo.

No wonder the actions of Petrobras in the Gulf have been widely divulged in speeches and seminars, and the progress achieved has been closely monitored by the U.S. industry, by the government, and by society.

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*risers – pipelines that connect the platform to the wells.
**umbilicals – multifunctional systems comprising tubes, energy cables, and optic cables that, when connected, enable communication between the oil wellheads on the seabed and the platforms.
*** hydrocarbons – chemical compounds formed by atoms of carbon and hydrogen. Oil and natural gas are natural hydrocarbons.

Safe from hurricanes

In the Gulf of Mexico, there is a season for hurricanes and many of them have already damaged platforms. As there are more than 1,000 units in operation in the region, we cannot be too careful. In 2009, Hurricane Ida caused the suspension of 29.6% of oil production and 27.5% of natural gas extraction. In 2008, Hurricane Ike devastated at least 49 platforms offshore. In 2005, Hurricane Katrina destroyed 44 platforms and Hurricane Rita, 64. The installation of FPSO BW Pioneer, with a disconnectable turret buoy, is a Petrobras solution to operate in the Cascade and Chinook fields in the Walker Ridge block, to deal with the storms in the region and, at the same time, exploit and produce oil and gas far from the coast.

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An approaching hurricane.

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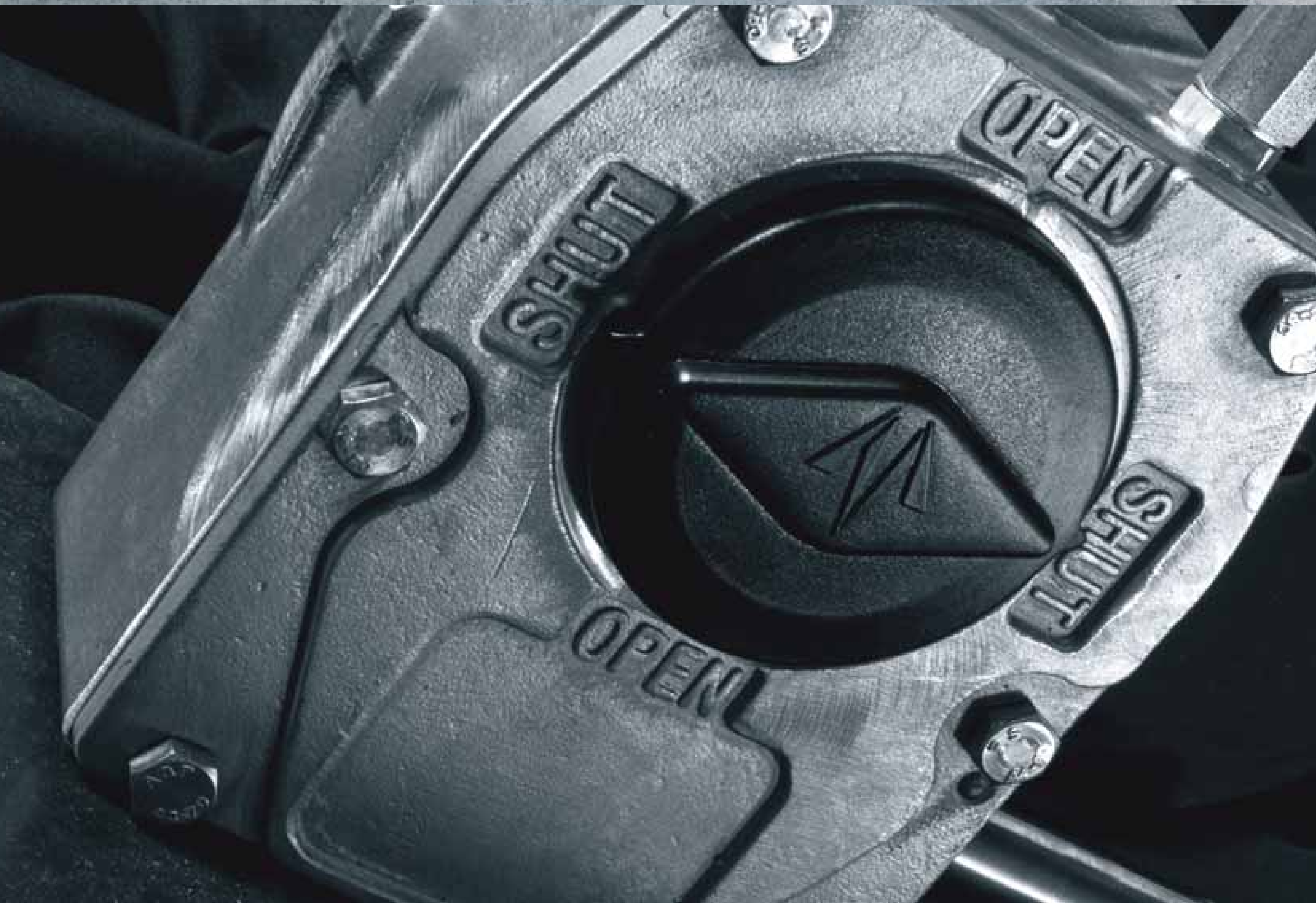

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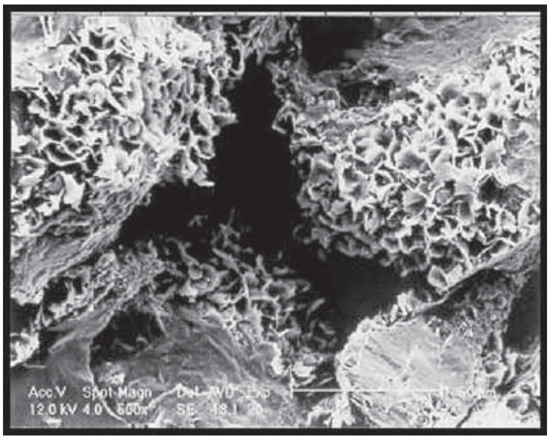
Formation Damage Laboratory Testing – Cost Effective Risk Reduction to Maximise Recovery

By Ryan McLaughlin, Ian Patey and Justin Green, Corex.

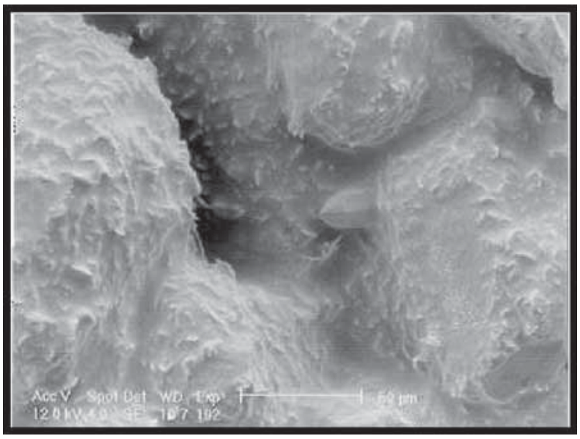
In recent years the oil and gas industry has seen rising costs associated with various operational activities such as drilling, completing and treating wells. However, economic pressure is not the only challenge within the market, environmental responsibility and the trend towards deeper drilling has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

Mechanisms which have an unfavourable economic impact can occur at any point during the life cycle of the filed such as drilling, completion, production, injection, treatment, and stimulation. These mechanisms which are termed as “Formation Damage” can manifest themselves in various ways, but fundamentally involve interactions between the reservoir (rock and fluids) and the introduced operational fluids and hardware. Drilling mud infiltration, poor mud-cake clean-up, fluid retention, fines mobilisation and pore blockage, fluid incompatibility and precipitation, emulsions/sludges, removal of cement, clay swelling, and sanding are all examples of mechanisms which can have an impact on productivity or injectivity.

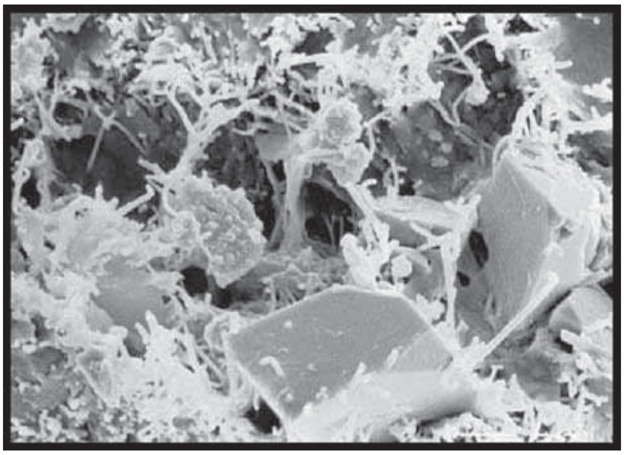
Laboratory testing can be performed to identify these damaging mechanisms, and with the correct interpretation useful recommendations can be made on ways of avoiding or removing them. The testing therefore becomes part of the quality management “Plan, Do, Study, Act” cycle: laboratory testing checks for problems or mechanisms, defines the options available for avoidance, tests the solutions for effectiveness, and pro-



Before Test Dry SEM image



After Test Cryogenic SEM image

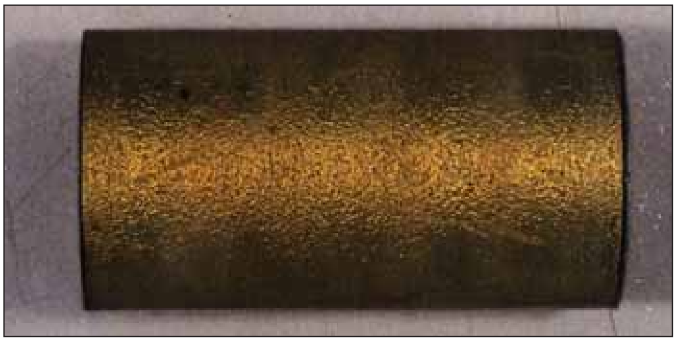


Damaged illite from unsuitable cleaning technique

vides feedback to aid in implementation. In terms of risk, the greater level of understanding can not only reduce risk, but add value to the planning process, as it is significantly cheaper to experiment in the laboratory than the field. A key aspect of laboratory testing is that it is direct measurement, whereas models are indirect or derived measurements; test data can therefore be used as inputs which consequently supplement or improve models. In addition, independent testing is key in the "calibration" of vendor recommendations on fluids and hardware, allowing comparison across vendors, fields, and operators.

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

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



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

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

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

Heavy oil

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

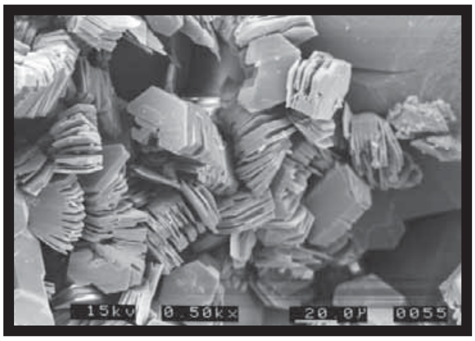
HPHT

High pressure, high temperature (HPHT) reservoirs, particularly tight gas, have also historically proved challenging to perform representative testing upon. Useful testing is especially vital in these fields, as any damaging mechanism can have a significant impact on permeability, and therefore the economic viability of a field. Identifying and avoiding damage before it occurs is essential in HPHT testing, and the testing needs to be performed at meaningful temperatures and pressures; the main innovation here is the design of equipment at Corex that allows wellbore operational testing to be carried out at temperatures of over 200ºC including (if required) humidification of gas at reservoir temperature.

SRA of injection operations and production drawdown operations

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

Corex's advanced HPHT Scale Rig performs many tests to establish Scale Risk Assessment (SRA).



Abundance of pore filling and grain coating Kaolinite clay booklets.

High-rate gas

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

Assessment for Halite rich reservoirs and well operations

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

Conclusion

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

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

Growth of Oil and Gas Industries in Brazil Drives Demand for a Higher Quality of Candidates

By Progisys Staff.

Brazil is now one of the world's fastest growing economies, the largest in South America and the tenth largest in the world. Its recent success story has been the result of an export-driven, mixed-market economy which supplements its incredible diversity of natural resources.

The Brazilian Energy Ministry says that the country will need to invest some 550 billion dollars in its energy industry to meet market demand by 2019. Infrastructure expansion subsequently results in a great demand for another finite resource, and that is people.

As the industry seeks to raise the bar for health and safety and environmental protection, a new generation of workers capable of using the raft of new plant management software and control systems is needed. Recent changes in health and safety in the oil and gas sector have also resulted in a rapid improvement of working practices. Each member of the onshore and offshore team must commit to a process of continuous professional development to be able to keep pace with these changes. Workers need to be highly competent and capable of working as part of an effective team to ensure safety standards are unimpeachable.

Finding the right candidate contributes to the successful implementation of health and safety and environmental practices on site. Progisys leads the way in providing the people that have the capability and desire for making Brazil's energy industry a role model for a changing world and recently opened an office in Rio de Janeiro,

Brazil, the company is well poised to provide staffing solutions which can support and drive organisations in this very dynamic South America region.

Gaëtan d'Oysonville, Country Manager for Progisys in Brazil, said, "We have proven to be strong in the timely and reliable fulfillment of our client's manpower needs and related logistical requirements. We have already successfully placed more than 100 engineers for over 12 different client projects in Angola. It was a huge human resource challenge that we were able to overcome because of the large and diversified talent pool upon which we are able to draw. We are confident that we will also be able to help new clients by placing candidates for a variety of these latest projects in Brazil."

The company has been recruiting role model professionals for the oil and gas industry for over 12 years and specialises in finding high-calibre role model professionals who empower and add value to some of the biggest energy projects on the planet.

Bernard Pailler, CEO of Progisys Group, said, "Operating in all types of challenging environments, we truly embrace the diversity in our multi-cultural teams across the globe. Brazil is a particular focus area for us because of the nation's insatiable hunger for growth and a push towards oil and gas net exports. We are proud to be able to say that we are now placed to serve the energy sector in Brazil, and be part of this exciting and rapid growth environment"

Triple-Porosity Models: One Further Step Towards Capturing Fractured Reservoir Heterogeneity

By Hasan A. Al-Ahmadi, SPE, Saudi Aramco, and R. A. Wattenbarger, SPE, Texas A&M University.

This paper was prepared for presentation at the 2011 SPE Saudi Arabia Section Technical Symposium and Exhibition held in AlKhobar, Saudi Arabia, 15–18 May 2011.

Abstract

Fractured reservoirs present a challenge in terms of characterization and modeling. Due to the fact that they consist of two coexisting and interacting media: matrix and fractures, not only we need to characterize the intrinsic properties of each medium but also accurately model how they interact. Dual-porosity models have been the norm in modeling fractures reservoirs. However, these models assume uniform matrix and fractures properties all over that medium. One further step into capturing the reservoir heterogeneity is to subdivide each medium and assign each one different property. In this paper, fractures are considered to have different properties and hence the triple-porosity model is introduced.

The triple-porosity model presented in this paper consists of three contiguous porous media: a matrix, less permeable microfractures and more permeable macrofractures. These media coexist and interact differently in the reservoir. It is assumed that flow is sequential following the direction of increased permeability and only macrofractures provide the conduit for fluids flow. Different solutions were derived based on different assumptions governing the flow between the fractures and matrix systems; i.e., pseudosteady state or transient flow in addition to different flow geometry; i.e., linear and radial. Some of these solutions are original. The model was confirmed mathematically by reducing it to dual-porosity system and numerically with reservoir simulation and applied to field cases. In addition, the solutions were modified to account for gas flow due to changing gas properties and gas adsorption in fractured unconventional reservoirs.

Introduction

A naturally fractured reservoir (NFR) can be defined as a reservoir that contains a connected network of fractures created by natural processes that have or predicted to have an effect on the fluid flow (Nelson 2001). Naturally fractured reservoirs contain more than 20% of the World's hydrocarbon reserves (Sarma and Aziz 2006). Moreover, most of the unconventional resources such as shale gas are also contained in fractured reservoirs.

Traditionally, dual-porosity models have been used to model NFRs where all fractures are assumed to have identical properties. Many dual-porosity models have been developed starting by Warren and Root (1963) sugar cube model in which matrix provides the storage while fractures provide the flow medium. The model assumed pseudosteady state fluid transfer between matrix and fractures. Since then several models were developed mainly as variation of the Warren and Root model assuming different matrix-fracture fluid transfer conditions.

However, it is more realistic to assume fractures having different properties. Thus, triple-porosity models have been developed as more realistic models to capture reservoir heterogeneity in NFRs. Models for more than three interacting media are also available in the literature. However, no triple-porosity model has been developed for linear flow system in fractured reservoirs. In addition, no triple-porosity (dual fracture) model is available for either linear or radial geometry that considers transient fluid transfer between matrix and fractures. These limitations are overcome in this paper.

Literature Review

Dual-Porosity Models. Naturally fractured reservoirs are usually characterized using dual-porosity models. The foundations of dual-porosity models were first introduced by Barenblatt et al., (1960). The model assumes pseudosteady state fluid transfer between matrix and fractures. Later, Warren and Root (1963) extended Barenblatt et al., model to well test analysis and introduced it to the petroleum literature. The Warren and Root model was mainly developed for transient well test analysis in which they introduced two dimensionless parameters, ω and λ. ω describes the storativity of the fractures system and λ is the parameter governing fracture-matrix flow. Dual-porosity models can be categorized into two major categories based on the interporosity fluid transfer assumption: pseudosteady state models and unsteady state models.

Pseudosteady State Models. Warren and Root (1963) based their analysis on sugar cube idealization of the fractured reservoir, Fig. 1. They assumed pseudo-steady

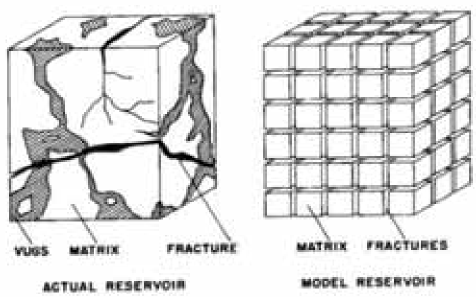


Fig. 1 – Idealization of the heterogeneous porous medium (Warren and Root 1963).

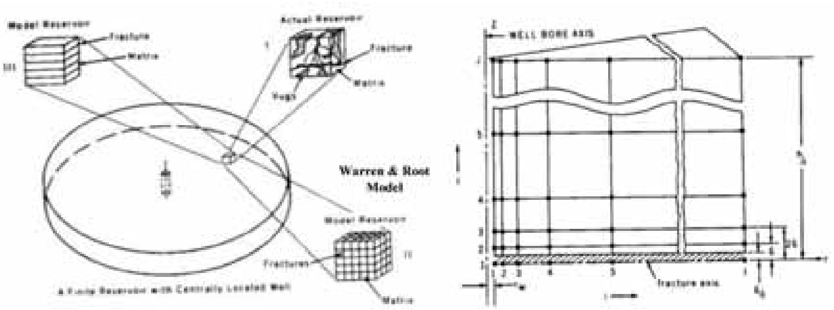


Fig. 2 – Idealization of the heterogeneous porous medium (Kazemi 1969).

state flow between the matrix and fracture systems. That is, the pressure at the middle of the matrix block starts changing at time zero. In their model, two differential forms (one for matrix and one for fracture) of diffusivity equations were solved simultaneously at a mathematical point. The fracture-matrix interaction is related by

$$q = \alpha \frac{k_m}{\mu}\left(p_m - p_f\right) \quad (1)$$

where q is the transfer rate, α is the shape factor, k_m is the matrix permeability, μ is the fluid viscosity and (p_m – p_f) is the pressure difference between the matrix and the fracture.

Unsteady State Models. Other models (Kazemi 1969; de Swaan 1976; Ozkan et al., 1987) assume unsteady-state (transient) flow condition between matrix and fracture systems. Kazemi (1969) proposed the slab dual-porosity model, Fig. 2, and provided a numerical solution for dual-porosity reservoirs assuming transient flow between matrix and fractures. His solution, however, was similar to that of Warren and Root except for the transition period between the matrix and fractures systems.

Triple-Porosity Models. The dual-porosity models assume uniform matrix and fractures properties throughout the reservoir which may not be true in actual reservoirs. An improvement to this drawback is to consider two matrix systems with different properties. This system is a triple-porosity system. Another form of triple-porosity is to consider two fractures systems with different properties in addition to the matrix. The latter is sometimes referred to as dual fracture model.

The first triple-porosity model was developed by Liu (1981, 1983). Liu developed his model for radial flow of slightly compressible fluids through a triple-porosity reservoir under pseudosteady state interporosity flow. This model, however, is rarely referenced as it was not published in the petroleum literature. In petroleum literature, the first triple-porosity model was introduced by Abdassah and Ershaghi (1986). Two geometrical configurations were considered: strata model and uniformly distributed blocks model. In both models, two matrix systems have different properties flowing to a single fracture under gradient (unsteady state) interporosity flow. The solutions were developed for the radial system.

Jalali and Ershaghi (1987) investigated the transition zone behavior of the radial triple porosity system. They extended the Abdassah and Ershaghi strata (layered) model by allowing the matrix systems to have different properties and thickness.

Al-Ghamdi and Ershaghi (1996) was the first to introduce the dual fracture triple-porosity model for radial system. Their model consists of a matrix and two fracture systems; more permeable macrofracture and less permeable microfracture. Two sub models were presented. The first is similar to the triple-porosity layered model where microfractures replace one of the matrix systems. The second is where the matrix feeds the microfractures under pseudosteady state flow which in turns feed the macrofractures under pseudosteady state flow condition as well. The macrofractures and/or microfractures are allowed to flow to the well.

Liu et al., (2003) presented a radial triple-continuum model. The system consists of fractures, matrix and cavity media.

Only the fractures feed the well but they receive flow from both matrix and cavity systems under pseudo-steady state condition.

Unlike previous triple-porosity models, the matrix and cavity systems are exchanging flow (under pseudosteady state condition) and thus it is called triple-continuum. Their solution was an extension of Warren and Root solution.

Wu et al., (2004) used the triple-continuum model for modeling flow and transport of tracers and nuclear waste in the unsaturated zone of Yucca Mountain. The system consists of large fractures, small fractures and matrix. They confirmed the validity of the analytical solution with numerical simulation for injection well injecting at constant rate in a radial system. In addition, they demonstrated the usefulness of the triple-continuum model for estimating reservoir parameters.

Dreier (2004) improved the triple-porosity dual fracture model originally developed by Al-Ghamdi and Ershaghi (1996) by considering transient flow condition between microfractures and macrofractures. Flow between matrix and microfractures is still under pseudosteady state condition. His main work (Dreier et al., 2004) was the development of new quadruple-porosity sequential feed and simultaneous feed models. He also addressed the need for nonlinear regression to match well test data and estimate reservoir properties in case of quadruple porosity model.

Linear Flow in Fractured Reservoir. Linear flow occurs at early time (transient flow) when flow is perpendicular to any flow surface. Wattenbarger (2007) identified different causes for linear transient flow including hydraulic fracture draining a square geometry, high permeability layers draining adjacent tight layers and early-time constant pressure drainage from different geometries.

El-Banbi (1998) developed new linear dual-porosity solutions for fluid flow in linear fractured reservoirs. Solutions were derived in Laplace domain for several inner and outer boundary conditions. These include constant rate and constant pressure inner boundaries and infinite and closed outer boundaries. Skin and wellbore storage effects have been incorporated as well. One important finding is that reservoir functions, f(s) , derived for radial flow can be used in linear flow solutions in Laplace domain and vice versa.

Bello (2009) demonstrated that El-Banbi solutions could be used to model horizontal well performance in tight fractured reservoirs. He then applied the constant pressure solution to analyze rate transient in horizontal multistage fractured shale gas wells.

Bello (2009) and Bello and Wattenbarger (2008, 2009, 2010) used the dual-porosity linear flow model to analyze shale gas wells. Five flow regions were defined based on the linear dual-porosity constant pressure solution. It was found that shale gas wells performance could be analyzed effectively by region 4 (transient linear flow from a homogeneous matrix). Skin effect was proposed to affect the early flow periods and a modified algebraic equation was proposed to account for it.

Ozkan et al., (2009) and Brown et al., (2009) proposed a trilinear model for analyzing well test in tight gas wells. Three contiguous media were considered: finite conductivity hydraulic fractures, dual-porosity inner reservoir between the hydraulic fractures and outer reservoir beyond the tip of the hydraulic fractures. Based on their analysis, the outer reservoir does not contribute significantly to the flow.

Al-Ahmadi et al., (2010) presented procedures to analyze shale gas wells using the slab and cube dual-porosity idealizations demonstrated by field examples.

New Analytical Triple-Porosity Solutions

As stated earlier, to the best of our knowledge, no triple-porosity model has been developed for linear flow system. In addition, no triple-porosity (dual fracture) model is available for either linear or radial geometry that considers transient fluid transfer between matrix and fractures in fractured reservoirs. Therefore, a triple-porosity model is developed (Al-Ahmadi 2010) in this paper and new solutions are derived for linear flow in fractured reservoirs. The triple-porosity system consists of three contiguous porous media: the matrix, less permeable microfractures and more permeable macrofractures. The main flow is through the macrofractures, which feed the well while they receive flow from the microfractures only. Consequently, the matrix feeds the microfractures only. Therefore, the flow is sequential from one medium to the other. In the petroleum literature, this type of model is sometimes called dual-fracture model.

To facilitate deriving the solution, it is chosen to model the fluid flow toward a horizontal well in a triple-porosity reservoir. El-Banbi (1998) solutions for linear flow in dual-porosity reservoirs will be used. However, new reservoir functions will be derived that pertain to the triple-porosity system and can be used in El-Banbi's solutions. Throughout this paper, matrix, microfractures and macrofractures are identified with subscripts m, f and F, respectively.

Linear Flow Solutions for Fractured Linear Reservoirs. El-Banbi (1998) was the first to present solutions to the fluid flow in fractured linear reservoirs. The analytical solutions for constant rate and constant pressure cases in Laplace domain are given by

Constant rate case:

$$\overline{p_{wDL}} = \frac{2\pi}{s\sqrt{s\,f(s)}}\left[\frac{1+\exp\left(-2\sqrt{s\,f(s)}\,y_{De}\right)}{1-\exp\left(-2\sqrt{s\,f(s)}\,y_{De}\right)}\right] \qquad (2)$$

Constant pressure case:

$$\frac{1}{\overline{q_{DL}}} = \frac{2\pi s}{\sqrt{s\,f(s)}}\left[\frac{1+\exp\left(-2\sqrt{s\,f(s)}\,y_{De}\right)}{1-\exp\left(-2\sqrt{s\,f(s)}\,y_{De}\right)}\right] \qquad (3)$$

Complete list of solutions are available in El-Banbi (1998). These solutions can be used to model horizontal wells in dual-porosity reservoirs (Bello, 2009). Accordingly, as will be shown later, they are equally applicable to triple-porosity reservoirs considered in this work since linear flow is the main flow regime. The fracture function, *f(s)* however, is different depending on the type of reservoir and imposed assumptions.

Derivations of the Triple-Porosity Analytical Solutions. A sketch of the triple-porosity dual-fracture model is shown in Fig. 3. The arrows indicate the flow directions where fluids flow from matrix to microfractures to the macrofractures - following the direction of increased

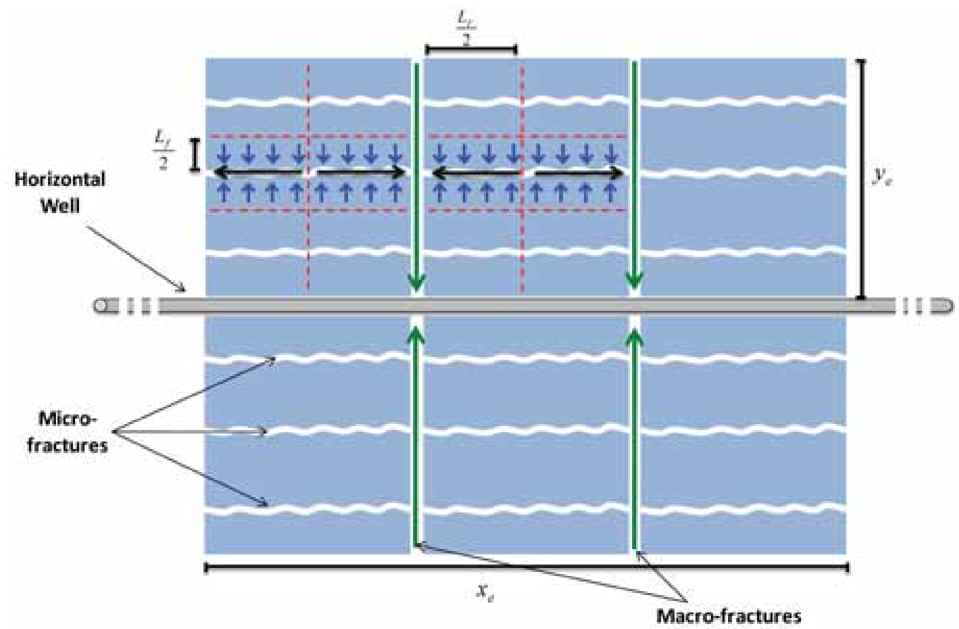


Fig. 3 – Top view of a horizontal well in a triple-porosity system with sequential flow. Arrows indicate flow directions (Al-Ahmadi 2010).

permeability - and finally to the well.

Model Assumptions. The analytical solutions are derived under the following assumptions:

1. Fully penetrating horizontal well at the center of a closed rectangular reservoir producing at a constant rate
2. Triple-porosity system made up of matrix, less permeable microfractures and more permeable macrofractures
3. Each medium is assumed to be homogenous and isotropic
4. Matrix blocks are idealized as slabs
5. Flow is sequential from one medium to the other; form matrix to microfractures to macrofractures
6. Flow of slightly compressible fluid with constant viscosity

Four Sub-models of the triple-porosity model are derived (Al-Ahmadi, 2010). The main difference between the models is the assumption of interporosity flow condition, i.e., pseudosteady state or transient. These models are shown graphically in Fig. 4. The analytical solution derivation for the fully transient (Model 1) is shown in this paper. More detailed solutions derivations for the other models are available in Al-Ahmadi (2010).

Definitions of Dimensionless Variables. Before proceeding with the derivations, the dimensionless variables are defined.

$$t_{DAc} = \frac{0.00633\, k_F t}{[\varphi c_t]_t \mu A_{cw}} \tag{4}$$

$$p_{DL} = \frac{k_F \sqrt{A_{cw}}(p_i - p)}{141.2\, qB\mu} \tag{5}$$

$$\omega_F = \frac{[\varphi V c_t]_F}{[\varphi V c_t]_t} \tag{6}$$

$$\omega_f = \frac{[\varphi V c_t]_f}{[\varphi V c_t]_t} \tag{7}$$

$$\omega_m = \frac{[\varphi V c_t]_m}{[\varphi V c_t]_t} = 1 - \omega_F - \omega_f \tag{8}$$

$$\lambda_{Ac,Ff} = \frac{12}{L_F^2}\frac{k_f}{k_F} A_{cw} \tag{9}$$

$$\lambda_{Ac,fm} = \frac{12}{L_f^2}\frac{k_m}{k_F} A_{cw} \tag{10}$$

$$z_D = \frac{z}{L_f/2} \tag{11}$$

$$x_D = \frac{x}{L_F/2} \tag{12}$$

$$y_D = \frac{y}{\sqrt{A_{cw}}} \tag{13}$$

ω and λ are the storativity ratio and interporosity flow

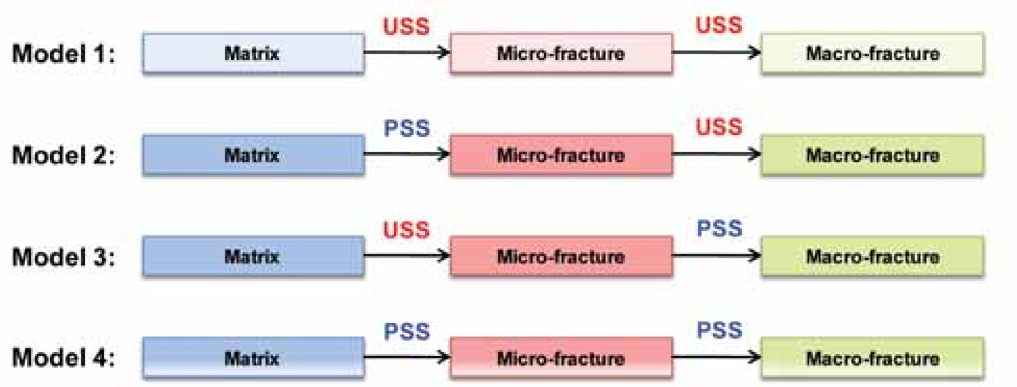


Fig. 4 – Sub-models of the triple-porosity model based on different interporosity flow condition assumptions. PSS: pseudosteady state. USS: unsteady state or transient. Arrows indicate flow directions.

parameter, respectively. k_F and k_f are the bulk (macroscopic) fractures permeabilities. Detailed parameters definitions are available in the nomenclature section in this paper.

Model 1: Fully Transient Triple-Porosity Model. The first Sub-model, Model 1, is the fully transient model. The flow between matrix and microfractures and that between microfractures and macrofractures are under transient condition. This model is an extension to the dual-porosity transient slab model (Kazemi 1969 Model). The derivation starts by writing the differential equations describing the flow in each medium.

Matrix:

$$\frac{\partial^2 p_{DLm}}{\partial z_D^2} = \left(1-\omega_f-\omega_F\right)\frac{3}{\lambda_{Ac,fm}}\frac{\partial p_{DLm}}{\partial t_{DAc}} \tag{14}$$

Microfractures:

$$\frac{\partial^2 p_{DLf}}{\partial x_D^2} = \omega_f \frac{3}{\lambda_{Ac,Ff}}\frac{\partial p_{DLf}}{\partial t_{DAc}} + \frac{\lambda_{Ac,fm}}{\lambda_{Ac,Ff}}\left.\frac{\partial p_{DLm}}{\partial z_D}\right|_{z_D=1} \tag{15}$$

Macrofractures:

$$\frac{\partial^2 p_{DLF}}{\partial y_D^2} = \omega_F \frac{\partial p_{DLF}}{\partial t_{DAc}} + \frac{\lambda_{Ac,Ff}}{3}\left.\frac{\partial p_{DLf}}{\partial x_D}\right|_{x_D=1} \tag{16}$$

The initial and boundary conditions in dimensionless form are as follows:

Matrix:

Initial condition: $p_{DLm}(z_D,0)=0$

Inner boundary: $\frac{\partial p_{DLm}}{\partial z_D}=0 \quad @ \; z_D=0$

Outer boundary: $p_{DLm}=p_{DLf} \quad @ \; z_D=1$

Microfractures:

Initial condition: $p_{DLf}(x_D,0)=0$

Inner boundary: $\frac{\partial p_{DLf}}{\partial x_D}=0 \quad @ \; x_D=0$

Outer boundary: $p_{DLf}=p_{DLF} \quad @ \; x_D=1$

Macrofractures:

Initial condition: $p_{DLF}(y_D,0)=0$

Inner boundary: $\left.\frac{\partial p_{DLF}}{\partial y_D}\right|_{y_D=0}=-2\pi$

Outer boundary: $\frac{\partial p_{DLF}}{\partial y_D}=0 \quad @ \; y_D=y_{De}={}^{y_e}/\!\sqrt{A_{cw}}$

The system of differential equations, Eqs. 14 to 16, can be solved using Laplace transformation as detailed in the Appendix. The fracture function, *f(s)*, for this model is given by

$$f(s)=\omega_F+\frac{\lambda_{Ac,Ff}}{3s}\sqrt{s\,f_f(s)}\,\tanh\left(\sqrt{s\,f_f(s)}\right)$$
$$f_f(s)=\frac{3\,\omega_f}{\lambda_{Ac,Ff}}+\frac{\lambda_{Ac,fm}}{s\,\lambda_{Ac,Ff}}\sqrt{\frac{3s\,\omega_m}{\lambda_{Ac,fm}}}\,\tanh\left(\sqrt{\frac{3s\,\omega_m}{\lambda_{Ac,fm}}}\right) \tag{17}$$

Table 1 – Fracture functions derived for triple-porosity model (New Solutions)	
Model	**Fracture Function, $f(s)$**
Triple-Porosity Fully Transient (Model 1)	$f(s)=\omega_F+\frac{\lambda_{Ac,Ff}}{3s}\sqrt{s\,f_f(s)}\,\tanh\left(\sqrt{s\,f_f(s)}\right)$ $f_f(s)=\frac{3\omega_f}{\lambda_{Ac,Ff}}+\frac{\lambda_{Ac,fm}}{s\,\lambda_{Ac,Ff}}\sqrt{\frac{3s\,\omega_m}{\lambda_{Ac,fm}}}\tanh\left(\sqrt{\frac{3s\,\omega_m}{\lambda_{Ac,fm}}}\right)$
Triple-Porosity Mixed Flow (Model 2)	$f(s)=\omega_F+\frac{\lambda_{Ac,Ff}}{3s}\sqrt{s\,f_f(s)}\,\tanh\left(\sqrt{s\,f_f(s)}\right)$ $f_f(s)=\frac{3\omega_f}{\lambda_{Ac,Ff}}+\frac{3\omega_m\lambda_{Ac,fm}}{s\omega_m\lambda_{Ac,Ff}+\lambda_{Ac,fm}\lambda_{Ac,Ff}}$
Triple-Porosity Mixed Flow (Model 3)	$f(s)=\omega_F+\frac{3\omega_f\lambda_{Ac,Ff}+\frac{\lambda_{Ac,Ff}\lambda_{Ac,fm}}{s}\sqrt{\frac{3s\,\omega_m}{\lambda_{Ac,fm}}}\tanh\left(\sqrt{\frac{3s\,\omega_m}{\lambda_{Ac,fm}}}\right)}{3\lambda_{Ac,Ff}+3s\omega_f+\lambda_{Ac,fm}\sqrt{\frac{3s\,\omega_m}{\lambda_{Ac,fm}}}\tanh\left(\sqrt{\frac{3s\,\omega_m}{\lambda_{Ac,fm}}}\right)}$
Triple-Porosity Fully PSS (Model 4)	$f(s)=\omega_F+\frac{\lambda_{Ac,Ff}\left[\omega_m\lambda_{Ac,fm}+\omega_f\left(s\omega_m+\lambda_{Ac,fm}\right)\right]}{\left(\lambda_{Ac,Ff}+s\omega_f\right)\left(s\omega_m+\lambda_{Ac,fm}\right)+s\omega_m\lambda_{Ac,fm}}$

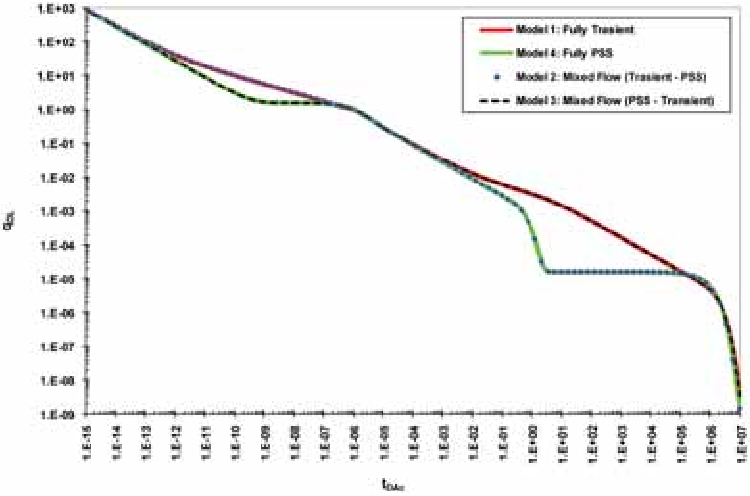


Fig. 5 – Comparison of the constant pressure solutions based on the four triple-porosity models assumptions (Al-Ahmadi, 2010).

Using the fracture function, Eq. 17 in Eqs. 2 or 3 will give the triple-porosity fully transient model response for constant rate or constant pressure cases, respectively in Laplace domain. The solution can then be inverted to real (time) domain using inverting algorithms like Stehfest Algorithm (Stehfest 1970).

Model 2: Mixed Flow Triple-Porosity Model. The second sub-model, Model 2, is where the interporosity flow between matrix and microfractures is under pseudosteady state while it is transient between microfractures and macrofractures. A similar model was derived by Dreier et al., (2004) for radial flow. However, their fracture

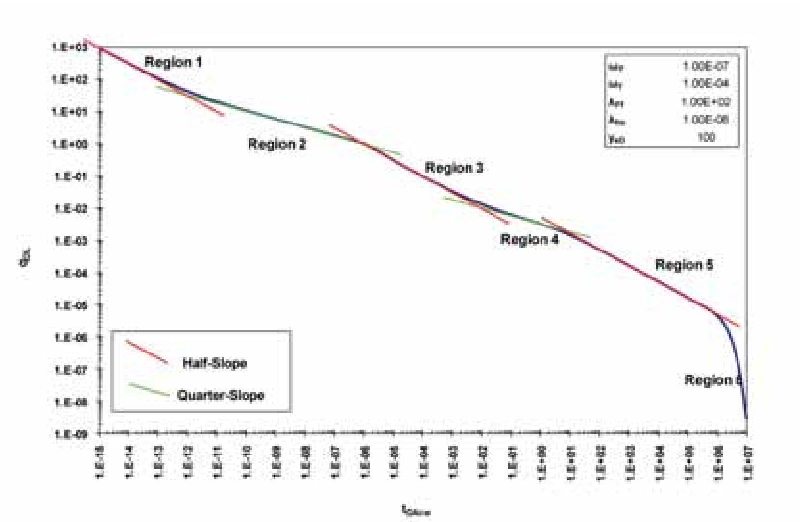


Fig. 6 – A log-log plot of triple-porosity solution. Six flow regions can be identified for Model 1 constant pressure solution. Slopes are labeled on the graph (Al-Ahmadi, 2010).

function is different since they had different definitions of dimensionless variables and used intrinsic properties for the transient flow.

Model 3: Mixed Flow Triple-Porosity Model. The third sub-model, Model 3, is where the flow between the matrix and microfractures is transient while the flow between microfractures and macrofractures is pseudosteady state. It is the opposite of Model 2.

Model 4: Fully PSS Triple-Porosity Model. The fourth sub-model, Model 4, is the fully pseudosteady state model. The flow between all three media is under pseudosteady state. This model is an extension of the Warren and Root dual-porosity pseudosteady state model. This model is also a limiting case of Liu et al., (2000; Wu et al., 2004) triple-continuum model if considering sequential flow and ignoring the flow component between matrix and macrofractures.

Table 1 summarizes the fractures functions derived for each sub model. The detailed derivations for all models are available in Al-Ahmadi (2010).

Triple-Porosity Solutions Comparison. Models 1 through 4 cover all possibilities of fluid flow in triple-porosity system under sequential flow assumption. Comparison of the constant pressure solution based on these models is shown in Fig. 5. As can be seen on the figure, Models 1 and 4 represents the end members while Models 2 and 3 are combination of these models. Model 2 follows Model 1 at early time but follows Model 4 at later time while Model 3 is the opposite. Considering rate transient analysis, Models 1 and 3 are more likely to be applicable to field data.

Flow Regions Based on the Analytical Solution. Since Model 1, the fully transient model, is the most general of all the four triple-porosity variations and shows all possible flow regions, the discussions in this paper will be limited to Model 1. Based on Model 1 constant pressure solution, six flow regions can be identified as

Table 2 – Input parameters for dual and triple-porosity solutions comparison

Dual-Porosity Parameters		Triple-Porosity Parameters	
ω	0.001	ω_F	0.001
λ	0.005	ω_f	0.999
y_{eD}	10	$\lambda_{Ac,Ff}$	0.005
		$\lambda_{Ac,fm}$	1×10^{-9}
		y_{eD}	10

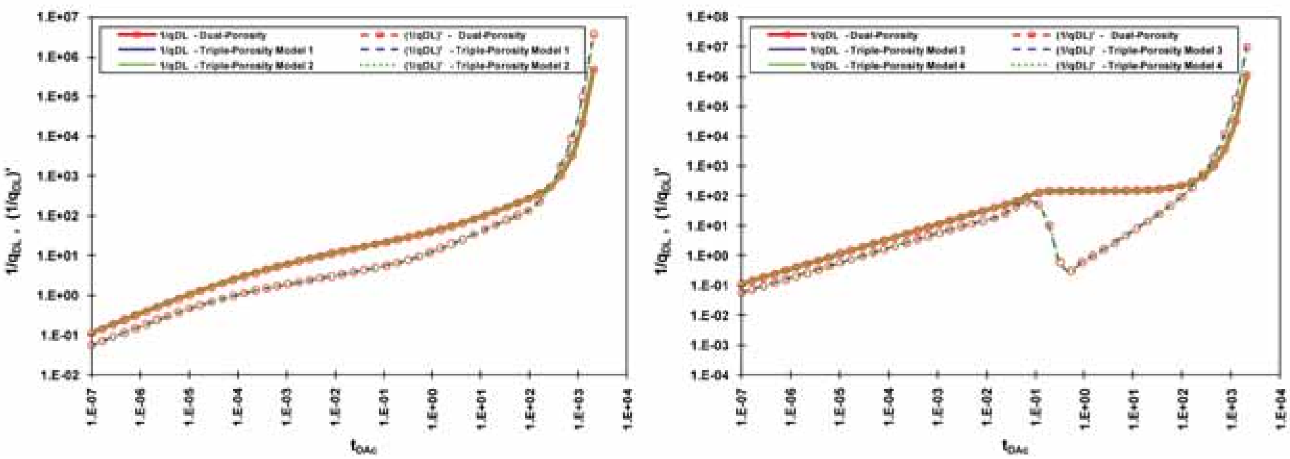


Fig. 7 –A log-log plot of transient dual-porosity (DP) and triple-porosity (TP) Models 1 and 2 solutions (on left) and pseudosteady state dual-porosity (DP) and triple-porosity (TP) Models 3 and 4 solutions (on right) for constant pressure linear flow case. In both figures, the two solutions are identical indicating the mathematical consistency of the new triple-porosity solutions.

the pressure propagates through the triple-porosity system (Al-Ahmadi, 2010). These flow regions are shown graphically on the log-log plot of dimensionless rate versus dimensionless time in Fig. 6. Regions 1 through 5 exhibit an alternating slopes of – 1⁄2 and – 1⁄4 indicating linear and bilinear transient flow, respectively. Region 6 is the boundary dominated flow and exhibits an exponential decline due to constant bottom-hole pressure. These flow regions are explained in details in the following sections.

Region 1. Region 1 represents the transient linear flow in the macrofractures only. The permeability of macrofractures is usually high and therefore, in most cases, this flow region will be very short. It may not be captured by most well rate measurement tools. This flow region exhibits a half-slope on the log-log plot of rate versus time.

Region 2. Region 2 is the bilinear flow in the macrofractures and microfractures. It is caused by simultaneous perpendicular transient linear flow in the microfractures and the macrofractures. This flow region exhibit a quarter-slope on the log-log plot of rate versus time.

Region 3. Region 3 is the linear flow in the microfractures system. It will occur once the transient flow in the macrofractures ends indicating the end of bilinear flow (region 2). This flow region exhibits a half-slope on the log-log plot of rate versus time.

Region 4. Region 4 is the bilinear flow in the microfractures and matrix. It is caused by the linear flow in the matrix while the microfractures are still in transient

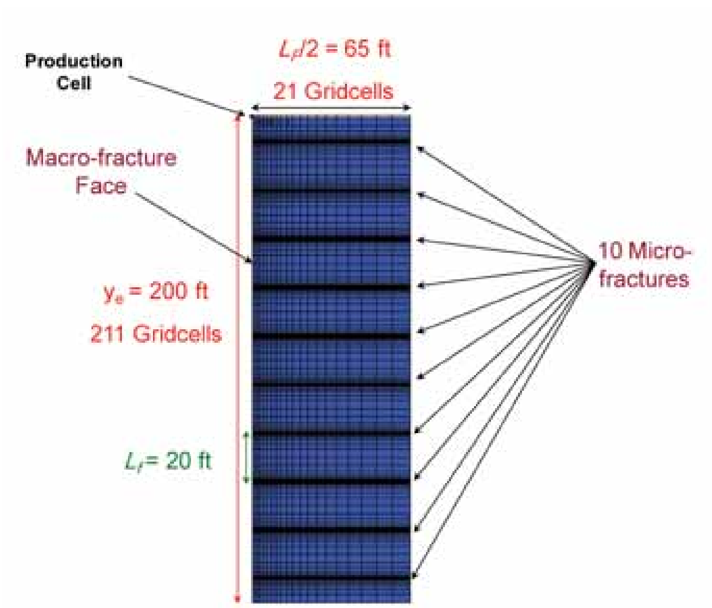


Fig. 8 – Top view of the CMG 2-D triple-porosity simulation model.

flow. This flow region exhibits a quarter-slope on the log-log plot of rate versus time. In most field cases, this flow region is the first one to be observed.

Region 5. Region 5 is the main and longest flow region in most field cases. It is the linear flow out of the matrix to the surrounding microfractures. This region exhibits a half-slope on the log-log plot of rate versus time. Analysis of this region will allow the estimation of fractures surface area available to flow, A_{cm}.

Region 6. Region 6 is the boundary dominated flow. It starts when the pressure at the center of the matrix blocks starts to decline. This flow is governed by exponential decline due to constant bottom-hole pressure.

Model verification

Mathematical Consistency of the Analytical Solutions. In this section, the solutions mathematical consistency is checked by reducing the triple-porosity model to its dual-porosity counterpart. This can be achieved by allowing the microfractures to dominate the flow and assigning to them the dual-porosity matrix properties from the dual-porosity system. In this case, the matrix-microfractures interporosity coefficient, $\lambda_{Ac,fm}$, is very small and the triple-porosity matrix storativity ratio, ω, is zero.

This comparison is shown for all models in the following figures. Table 2 shows the data used for comparison.

Models 1 and 2 are reduced to the transient slab dual-porosity model since the flow between microfractures and macrofractures is under transient conditions in the two models. Models 3 and 4, however, are reduced to the pseudosteady state dual-porosity model since the flow between microfractures and macrofractures is under pseudosteady state condition in the two models. As shown in Fig. 7, the triple-porosity solutions are identical to their dual-porosity counterpart. This confirms the mathematical consistency of the new triple-porosity solutions.

Comparison to Simulation Model. A triple-porosity simulation model was built explicitly using CMG reservoir simulator to understand the behavior of triple-porosity reservoirs and to verify the derived analytical solutions. The model considers the flow toward a horizontal well in a triple-porosity reservoir. One representative segment is modeled which represents one quadrant of the reservoir volume around a macrofracture. This segment contains ten microfractures orthogonal to the macrofractures at 20 ft fracture spacing. The model is a 2-D model with 21 gridcells in the x-direction, 211 gridcells in y-direction and only one cell in the z-direction. A top view of the model is shown in Fig. 8. All matrix, microfractures and macrofractures properties are assigned explicitly. In addition, the simulation model as-

Table 3 – Input parameters for dual and triple-porosity solutions comparison for radial flow

Dual-Porosity Parameters		Triple-Porosity Parameters	
ω	0.001	ω_F	0.001
λ	0.001	ω_f	0.999
r_{eD}	10	$\lambda_{Ac,Ff}$	0.001
		$\lambda_{Ac,fm}$	1×10^{-9}
		r_{eD}	10

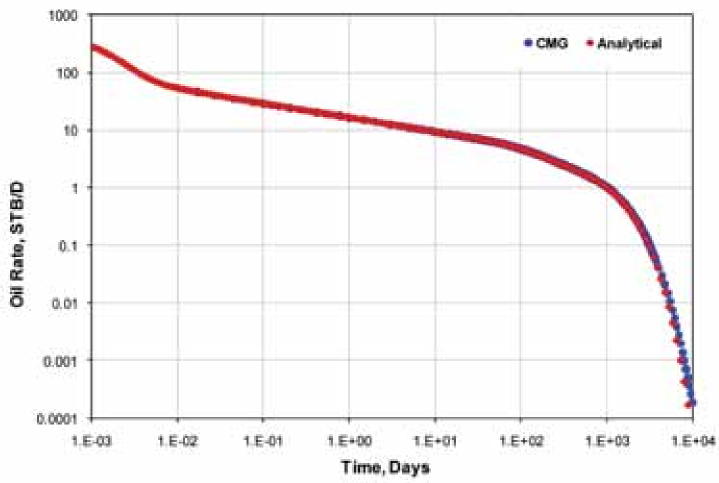


Fig. 9 – Match between simulation and analytical solution results for oil reservoir case. (kF,in = 1000 md, kf,in = 1 md and km = 1.5x10 md) (Al-Ahmadi 2010).

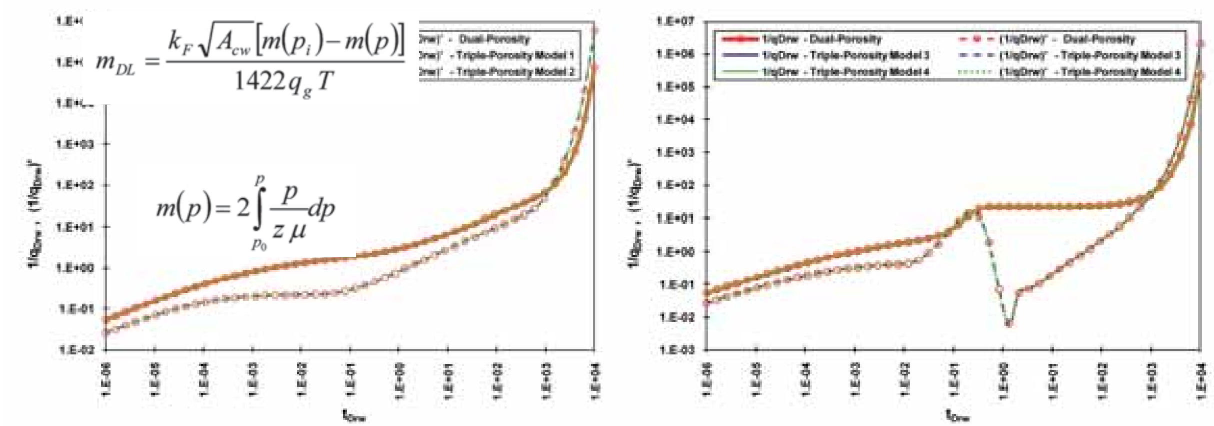


Fig. 10 – Log-log plot of dual-porosity and triple-porosity constant pressure solutions for radial flow. On the left is the transient solution and on right is the pseudosteady solution (Al-Ahmadi 2010).

sumes constant connate water saturation.

The simulation model was run for many cases by changing the three porosities and permeabilities of the three media and the simulation results are compared to that of the analytical solutions for each case. All cases were matched with analytical solutions and thus confirming their validity. A result of one case for oil reservoir is shown in Fig. 9.

Applicability of Triple-Porosity Solutions for Radial Flow. Although the triple-porosity solutions derived in this paper were for linear flow, they are equally applicable to radial flow following El-Banbi (1998) work. The differential equation in Laplace domain that governs the flow in the macrofractures in case of radial system is given by

$$\frac{1}{r_D}\frac{\partial}{\partial r_D}\left(r_D\frac{\partial \overline{p_{DF}}}{\partial r_D}\right) - s\,f(s)\,\overline{p_{DF}} = 0 \qquad (18)$$

The constant pressure solution for a closed reservoir is given by (El-Banbi 1998)

$$\frac{1}{q_D} = \frac{s\left[I_0\left(\sqrt{s\,f(s)}\right)K_1\left(\sqrt{s\,f(s)}\,r_{eD}\right) + I_1\left(\sqrt{s\,f(s)}\,r_{eD}\right)K_0\left(\sqrt{s\,f(s)}\right)\right]}{\sqrt{s\,f(s)}\left[I_1\left(\sqrt{s\,f(s)}\,r_{eD}\right)K_1\left(\sqrt{s\,f(s)}\right) + I_1\left(\sqrt{s\,f(s)}\right)K_1\left(\sqrt{s\,f(s)}\,r_{eD}\right)\right]} \qquad (19)$$

The fracture functions, *f(s)*, derived for all the models can be used in the radial flow solutions as well. Fig. 10 shows comparison between radial dual-porosity solutions and the new triple-porosity solutions reduced to their dual-porosity counterpart and applied to radial flow. Data used for comparison are shown in Table 3. The solutions are identical indicating the applicability of the new triple-porosity solutions derived in this work to radial flow.

Application to Gas Flow. It is important to note that the above solutions were derived for slightly compressible fluids and thus are applicable to liquid flow only. However, they can be applied to gas flow by using real gas pseudo-pressure, *m(p)*, instead of pressure to linearize the left-hand side of the diffusivity equation. Therefore, the dimensionless pressure variable will be defined in terms of real gas pseudo-pressure as:

$$m_{DL} = \frac{k_F\sqrt{A_{cw}}\left[m(p_i) - m(p)\right]}{1422\,q_g\,T} \qquad (20)$$

where *m(p)* is the real gas pseudo-pressure defined as (Al-Hussainy et al. 1966):

$$m(p) = 2\int_{p_0}^{p}\frac{p}{z\,\mu}dp \qquad (21)$$

With the above linearization, the derived solutions are applicable to the transient flow regime for gas flow.

However, once the reservoir boundaries are reached and average reservoir pressure starts to decline, the gas properties will change considerably especially the gas viscosity and compressibility. Therefore, the solutions have to be corrected for changing fluid properties. This is usually achieved by using pseudo-time or material balance time. An example of these transformations is the Fraim and Wattenbarger (1987) normalized time defined as

$$t_n = \int_0^t \frac{(\mu c_t)_i}{\mu(\bar{p})c_t(\bar{p})} d\tau \tag{22}$$

Thus, with these two modifications, the analytical solutions derived in this work are applicable to gas flow.

Accounting for Adsorbed Gas. Unlike tight gas reservoirs, gas in shale reservoirs is stored as compressed (free) gas and adsorbed gas. Adsorbed gas does not usually flow until the pressure drops below the sorption pressure. Adsorbed gas can be accounted for using Langmuir isotherm which defines the adsorbed gas volume as:

$$V = V_L \frac{p}{(p + p_L)} \tag{23}$$

where

V: Volume of gas currently adsorbed (scf/cuf)
V_L: Langmuir's volume (scf/cuf)
p_L: Langmuir's pressure (psia)
p_{Lp}: Reservoir pressure (psia)

Therefore, the analytical solutions have to account for the adsorbed gas before applying them to shale gas wells. This can be achieved by modifying the gas compressibility definition to include adsorbed gas. Following Bumb and McKee (1988), the modified total compressibility is defined as:

$$c_t^* = c_f + c_g S_g + c_w S_w + c_d \tag{24}$$

where c_d is the desorbed gas compressibility given by:

$$c_d = \frac{\rho_{g_{sc}} V_L p_L}{\varphi \bar{\rho}_g (p_L + \bar{p})^2} = \frac{B_g V_L p_L}{\varphi (p_L + \bar{p})^2} \tag{25}$$

Thus, to account for adsorption, c^*_t instead of c_t will be used in the analytical solutions to be applicable to shale gas wells.

For material balance calculations, the modified compressibility factor (z^*) is used instead of z (King 1993). z^* is defined as:

$$z^* = \frac{z}{(1 - S_{wi}) + \dfrac{V_L T p_{sc} z}{\varphi (p + p_L) T_{sc} z_{sc}}} \tag{26}$$

Then the gas material balance equation becomes:

$$\frac{\bar{p}}{z^*} = \frac{p_i}{z_i^*}\left(1 - \frac{G_p}{G}\right) \tag{27}$$

The *OGIP* accounting for free and adsorbed gas can be calculated using the following volumetric equation (Samandarli 2011):

$$G = V_b\left[\left(\frac{\varphi S_{gi}}{B_{gi}}\right) + (1 - \varphi)\left(V_L \frac{p_i}{p_i + p_L}\right)\right] \tag{28}$$

Field Application

Tight reservoirs such as shale oil or shale gas are perfect field case to apply this model due to the large contrast in the three porous media permeability values. Horizontal wells placed in these reservoirs are usually hydraulically fractured due to low matrix permeability. Natural fractures usually exist in these reservoirs as well. The case presented here is from a shale gas reservoir.

Shale Gas reservoirs play a major role in the United State natural gas supply as they are aggressively developed capitalizing on new technologies, namely horizontal wells with multistage fracturing. It has been observed that these wells behave as though they are controlled by transient linear flow (Bello 2009; Bello and Wattenbarger 2008, 2009, 2010; Al-Ahmadi et al., 2010). According to Medeiros et al., (2008) linear flow is the dominant flow regime for fractured horizontal wells in tight formations for most of their productive lives. This behavior is characterized by a negative half-slope on the log-log plot of gas rate versus time and a straight line on the $[m(p_i) - m(p_{wf})]/q_g$ vs. $t^{0.5}$ plot (the square root of time plot).

Some shale gas wells, however, exhibit a bi-linear flow just before the linear flow is observed. This behavior is characterized by a negative quarter-slope on the log-log plot of gas rate versus time or a straight line on the $[m(pi) - m(p_{wf})]/q_g$ vs. $t^{0.25}$ plot. The bi-linear flow is due to two perpendicular transient linear flows occurring simultaneously in two contiguous systems. These could be microfractures and matrix or microfractures and macrofractures systems.

Previously, shale gas wells have been modeled using linear dual-porosity models (Bello 2009; Bello and Wattenbarger 2008, 2009, 2010; Al-Ahmadi et al., 2010). In these models, the matrix was assumed "homogeneous" although it might be enhanced by natural fractures by having high effective matrix permeability. In addition, orthogonal fractures are assumed to have identical properties. However, most if not all of horizontal wells drilled in shale gas reservoirs are hydraulically fractured. As the hydraulic fractures propagate, they re-activate the pre-existing natural fractures (Gale et al., 2007). The result will be two orthogonal fractures systems with different properties. Therefore, dual porosity model will not be sufficient to characterize these reservoirs. As a result, the triple-porosity model with fully transient flow assumption (Model 1) will be used to model horizontal shale gas wells. For this specific case, macrofractures are the hy-

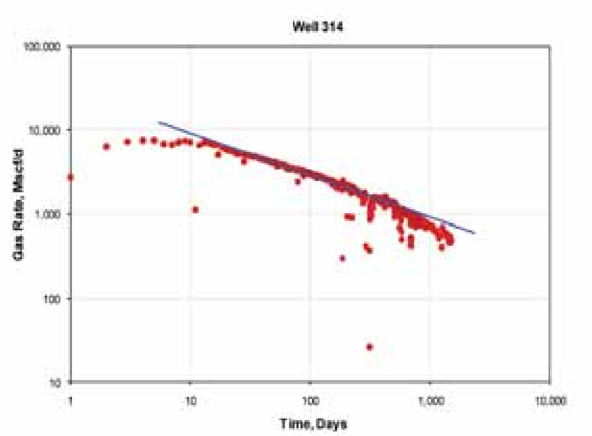


Fig. 11 – Log-Log plot of gas rate versus time for a horizontal shale gas wells. The well exhibits a linear flow for almost two log cycles. The blue and indicates a half-slope.

Table 4 – Well 314 data

"Known" Data			Assumed Data		
L_F	(ft)	106	φ_F		0.2
n_F		28	w_F	(ft)	0.1
φ_m		0.06	φ_f		0.01
k_m	(md)	1.5×10^{-4}	w_f	(ft)	0.01
h	(ft)	300			
x_e	(ft)	2968			
μ_{gi}	(cp)	0.0201	Unknown Data		
B_{gi}	(rcf/scf)	0.00509			
c_{ti}	(psi^{-1})	300×10^{-6}	$k_{F,in}$	(md)	
p_i	(psi)	2950	$k_{f,in}$	(md)	
p_{wf}	(psi)	500	y_e	(ft)	
$m(p_i)$	(psi^2/cp)	5.97×10^{8}	L_f	(ft)	
$m(p_{wf})$	(psi^2/cp)	2.03×10^{7}			
T	(°R)	610			
S_{wi}		0.3			

draulic fractures while microfractures are the natural fractures.

Analysis Procedure. Due to the large number of variables involved in the triple-porosity model, nonlinear regression will be utilized to estimate a set of unknown parameters by matching the well's production rate. Other parameters may be assumed or estimated through other methods. Including many variables in the regression may lead to non-uniqueness of the converged solution. The parameters to be found by regression are fractures intrinsic permeabilities, drainage area half-width (hydraulic fracture half-length) and natural fractures spacing. After the match is obtained, the well model is fully defined. Hence, the OGIP can be calculated by volumetric method and well future production can be forecasted.

Nonlinear Regression. The triple-porosity model presented in this paper needs at most five parameters; namely two ω's, two λ's and y_{De}. In addition, these calculated parameters depend on reservoir properties which have to be estimated. This leads to estimation of many parameters that may not be known or needs to be calcu-

Table 5 – Regression results for Well 314			
	First Guess	LAV Results (Without Adsorption)	LAV Results (With Adsorption)
$k_{F,in}$	100	10.9	9.4
$k_{f,in}$	1	0.26	0.33
L_f	10	24	22.4
y_e	300	205	160
Iterations	–	18	21
OGIP, *Bscf*	–	3.01	4.05

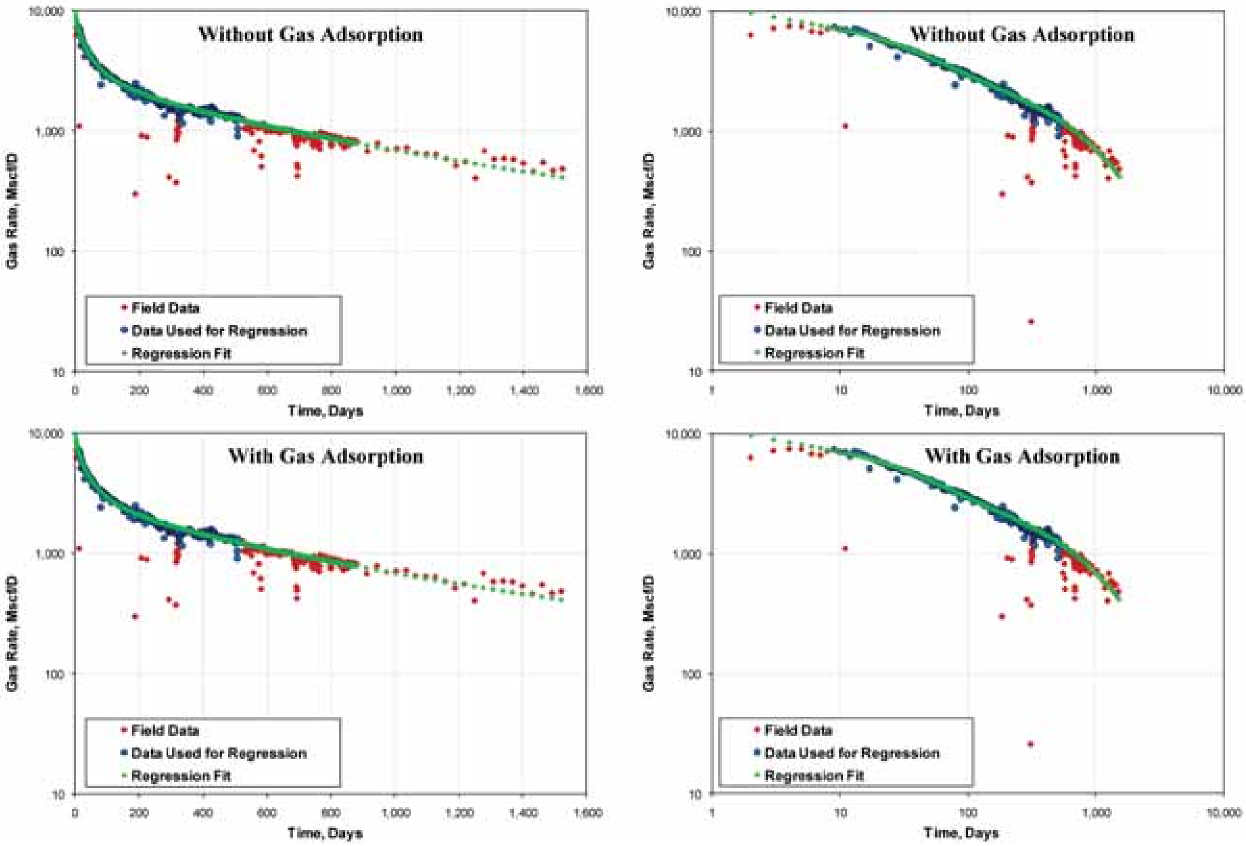


Fig. 12 – Matching Well 314 production history using the regression results without (top) and with (bottom) adsorption. On the left is the decline curve plot and log-log plot is on the right for gas rate vs. time.

lated. Therefore, the need for regression arises in order to match field data and have a good estimate of the sought reservoir or well parameters. In automated well test interpretations, the common regression methods are the least squares (LS), least absolute value (LAV) and modified least absolute value minimization (Rosa and Horne 1995, 1996). It was found, however, that the least absolute value regression method is the most appropriate in matching noisy data and can be used effectively with triple-porosity model to match field data (Al-Ahmadi 2010).

However, in order to get the most accurate results with regression, data that shows special trends should be included in the regression. For example, if the data that shows linear flow was only included in the regression and the data that shows a bi-linear flow just before it was ignored, the data will be matched but the solutions will not be representative as if that data was also included. In short, as expected the more data included in the regression, the more accurate the results will be.

Field Case. A field case from the Barnett Shale will be used to demonstrate the application of the triple-porosity model. Gas rate history for these wells is shown in Fig. 11. The fully transient model (Model 1) with non-linear regression and normalized time will be applied. Gas adsorption will be included in the analysis as well. The well is matched with the analytical solutions by first assuming no adsorbed gas and then including gas adsorption. Comparisons are made for each well. The following adsorption data are used for the Barnett Shale (Mengal 2010):

V_L = 96 scf/ton
p_L = 650 psi
Bulk Density = 2.58 gm/cc

Well 314 is a horizontal well with multistage hydraulic fracturing treatment producing at a constant bottom-hole pressure.

The well production rate exhibits a half-slope on the log-log plot of rate versus time indicating a linear flow. However, the early and late data deviate from this trend. The early deviation may be due to skin effect due to the presence of fracturing job water in the hydraulic fractures making it difficult for the gas to start flowing to the well (Bello and Wattenbarger 2009; Al-Ahmadi et al., 2010). The later deviation is due to either start of boundary dominated flow (BDF) or reduction of well's drainage area due to drilling nearby well. In this work, no skin effect is considered and the later deviation will be dealt with as BDF. However, if the well is affected by skin, it results in a lower permeability value for the hydraulic fractures.

Table 4 summarizes well 314 data in addition to other assumed parameters. From the hydraulic fractures treatment, hydraulic fractures spacing is calculated assuming each perforation cluster corresponds to a hydraulic fracture. In addition, drainage area length, x_e, is the same as perforated interval. The matrix porosity and permeability used are the most available in the literature for the Barnett Shale. Representative values are assumed for fractures intrinsic porosity and width. Finally, the fractures intrinsic permeabilities, drainage area half-width and natural fractures spacing will be found by regression.

Regression results are shown in Table 5 and Fig. 12 with and without adsorption using LAV method.

From the regression results above, the hydraulic fractures intrinsic permeability is more than an order of magnitude compared to that of the natural fractures. In addition, the natural fractures permeability is about three orders of magnitude compared to the matrix permeability. Furthermore, the natural fracture spacing is about 23 ft indicating that matrix is in fact enhanced by natural fractures.

Including adsorption did not change the estimate of fractures intrinsic permeabilities or the natural fractures spacing but it had a big impact on drainage area half-width and consequently OGIP. Thus, including adsorption reduces the reservoir size while increasing its gas content by 35%. The same matrix porosity was used in both cases which may not be physically correct. The calculated *OGIP* is 3.01 *Bscf* if adsorbed gas is ignored. Al-Ahmadi et al., (2010) estimated 2.74 *Bscf* for *OGIP* for this well using linear dual-porosity model. The two estimates are within 10% relative error.

Knowing all the triple-porosity parameters, the whole well production history is forecasted as shown in Fig. 12 based on the regression results for the first 500 days. As can be seen, the model very well reproduced the well production trend with and without adsorption as shown on the log-log and decline curve plots.

Conclusions

The major conclusions from this work can be summarized as follows:

1. Triple-porosity models are proposed as a more practical technique for capturing fractured reservoir heterogeneity by allowing fractures to have different properties.
2. New triple-porosity (dual-fracture) solutions have been developed for fractured linear reservoirs and proved to be applicable to radial flow geometry as well.
3. Six flow regions can be identified for fully transient triple-porosity model (Model 1).
4. The new model has been verified by reducing it to simpler dual porosity models and by comparing it to reservoir simulation.
5. The derived solutions are also applicable to gas flow using gas real gas pseudo-pressure and normalized time.
6. Triple-porosity fully transient model (Model 1) is ap-

plicable to fractured shale gas horizontal wells when gas adsorption is incorporated. The model can be used to match field data, characterize well drainage area, determine reservoir size and *OGIP* and forecast future production.

Nomenclature

A_{cw}	cross-sectional area to flow defined as $2hx_e$, ft^2
A_{cm}	total matrix surface area draining into fracture system, ft^2
B_{gi}	formation volume factor at initial reservoir pressure, rcf/scf
c_t	total compressibility, psi^{-1}
E	objective function
$\bar{g}$	objective function gradient
h	reservoir thickness, ft
H	Hessian matrix
k_F	macrofractures bulk permeability, md
k_f	microfracture bulk permeability, md
$k_{F,in}$	macrofracture intrinsic permeability, md
$k_{f,in}$	microfracture intrinsic permeability, md
k_m	matrix permeability, md
L_F	macrofractures spacing, ft
L_f	microfractures spacing, ft
$m(p)$	real gas pseudo-pressure, psi^2/cp
p_D	dimensionless pressure (transient triple poros ity model)
p_i	initial reservoir pressure, psi
p_L	Langmuir's pressure, psi
p_{wf}	wellbore flowing pressure, psi
q_D	dimensionless rate (transient triple porosity model)
q_{DL}	dimensionless rate based on $A_{cw}^{0.5}$ and k_F (rec tangular geometry, triple porosity)
q_g	gas rate, Mscf/day
r_w	wellbore radius, ft
S_{gi}	initial gas saturation, fraction
S_{wi}	initial water saturation, fraction
T	absolute temperature, °R
t	time, days
t_{DAcw}	dimensionless time based on A_{cw} and k_F (rec tangular geometry, triple-porosity)
t_{esr}	time to end of straight line on the square root of time plot, days
V_b	total system bulk volume, ft^3
V_L	Langmuir's volume, scf/ton (or scf/cuf)
V	bulk volume fraction, dimensionless
x_e	drainage area length (rectangular geometry), ft
y_{De}	dimensionless reservoir half-width (rectangu lar geometry)
y_e	drainage area half-width (rectangular geom etry), equivalent to fracture half-length, ft

Greek symbols

α	Warren and Root shape factor
$\vec{\alpha}$	vector of unknown regression parameters
λ	dimensionless interporosity parameter
μ	viscosity, cp
ω	dimensionless storativity ratio
ϕ	porosity

Subscripts

i	initial
F	macrofracture (hydraulic fracture)
f	microfracture (natural fracture)
m	matrix
$t = F+f+m$	total system (macrofracture +microfracture + matrix)

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

By Clive Cornwall, Corex (UK) Ltd.

Introduction

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

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

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

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

This paper seeks to make the case for an integrated core analysis and petrographic screening study, in conjunction with one or more RPM formulations, to determine which product is most suited to the prevailing conditions. It also affords an opportunity to modify a particular RPM formulation to maximise its potential and where a clean-up chemical is to be used, to ensure it will have the desired effect.

Background

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

The Relative Permeability Modifiers that would benefit from an integrated package of core analysis screening are the non-sealing, water soluble polymers, whose purpose is to reduce the flow of water into the wellbore, without unduly suppressing the production of the oil phase. The manifestation of the alteration in the flow patterns is found in the effective water and oil permeabilities, and in the fluid saturation profiles. Such pa-

Mineral	Percent
Quartz	83
Feldspar	5
Clays	9
Other Minerals	3

Table 1 – Typical Mineralogical Content of Berea Sandstone

rameters can be measured under reservoir conditions of pressure and temperature, with crude oil and simulated formation brine, as part of the core analysis screening.

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

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

Candidate Test Formats

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

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

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

Wettability – Comments and Determination

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

The point has been made that rock properties such as relative permeability and capillary pressure, depend on the distribution of water and oil in the pore space. In order for laboratory measurements to be representative, it is necessary for the pore level distribution of the fluids and the wettability to be the same in the laboratory as in the reservoir. Unfortunately much, if not all, of the laboratory based proving of the RPM chemicals has been conducted on standard sandstone plugs, such as Berea (see table 1). These sandstone plugs are cleaned with solvents prior to saturation with brine and oil, which creates a uniform wetting preference. Anderson in his review

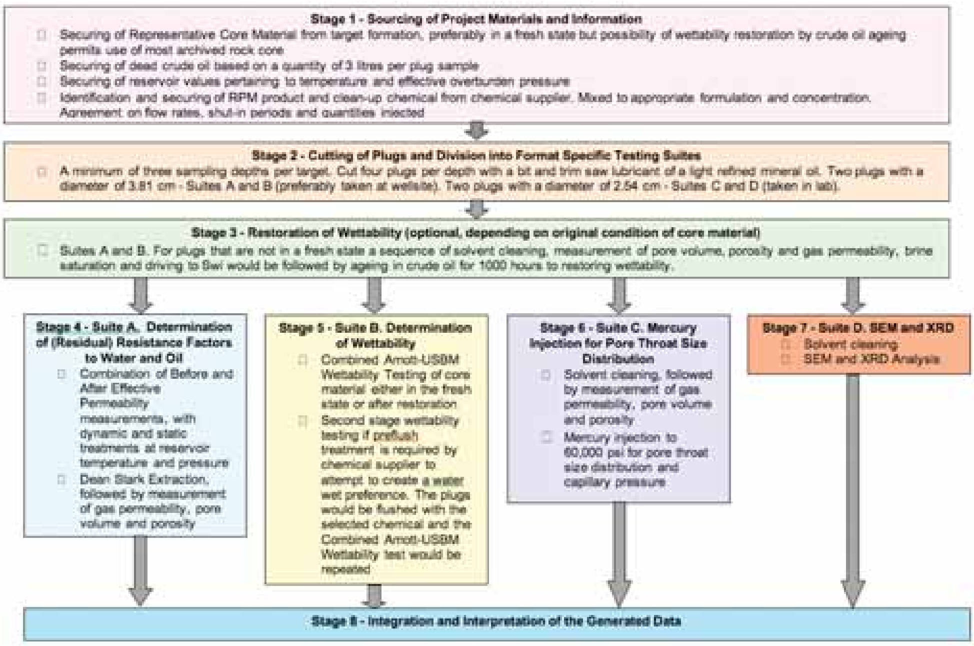


Figure 1 - Flow Diagram for Programme of RPM Screening

of the technical literature with respect to rock-oil-brine interactions and wettability observes that when all surface contaminants are carefully removed, most minerals, including quartz, carbonates and sulphates are strongly water-wet.

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

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

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

The Condition of the Test Core

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

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

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

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

Formulation A

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

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

Formulation B

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

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

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

adapted to the specific case.

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

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

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

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

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

This generic sequence can be modified to reflect the specific requirement of the chemical supplier, in conjunction with the operator, in terms of flow rates, shut-in periods and quantities injected. The selection of the flow rates is of particular importance to minimize polymer stripping during subsequent formation to wellbore production. The flushing cycles can also be altered should there be a need for over-flushing or focusing on a single phase rather than both water and oil. Additional analysis may also be included to monitor the amount of RPM polymer present in the effluent to chart the rate of displacement associated with prolonged flushing after treatment.

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

Principal Components:

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

Fig 2. Reservoir Conditions Test Rig for rpm Screening.

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

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

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

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

Mercury Injection Capillary Pressure and Petrographic Analysis

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

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

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

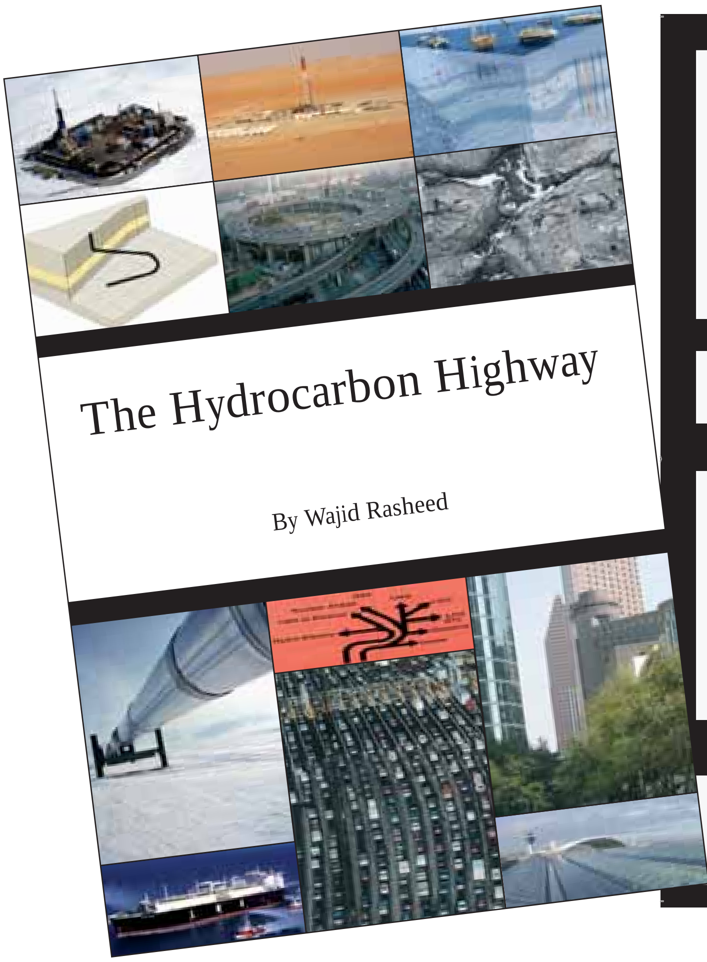
Conclusions

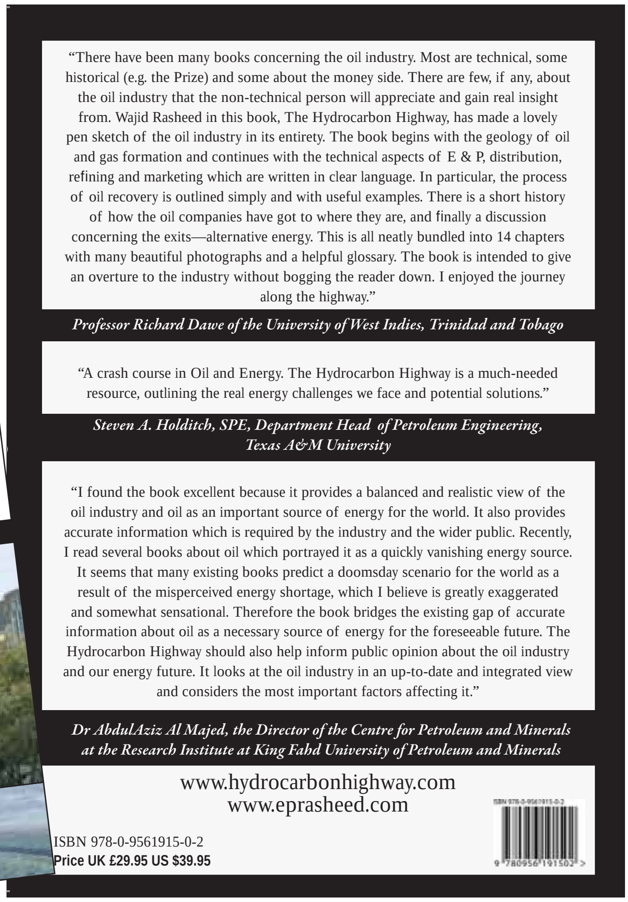
To maximise the benefits of RPM treatments, whether directly into the matrix or associated with fracturing, an understanding of the properties of the target formation is vital. This knowledge base will also assist in selecting the pre-treatment processes and solutions that are applied to create a water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

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

Pregnant Ladies and Fishbones

A Chapter from The Hydrocarbon Highway, by Wajid Rasheed





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

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

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

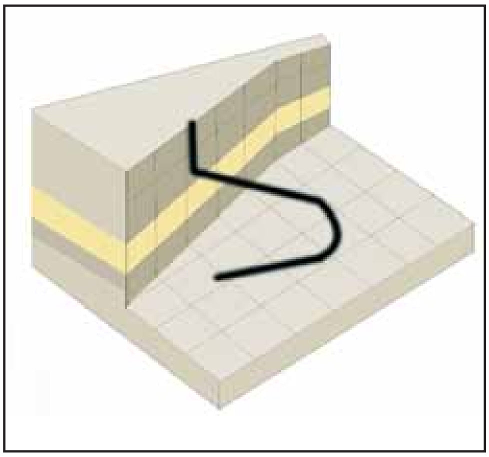


Figure 1 - Pregnant Lady Well Profile

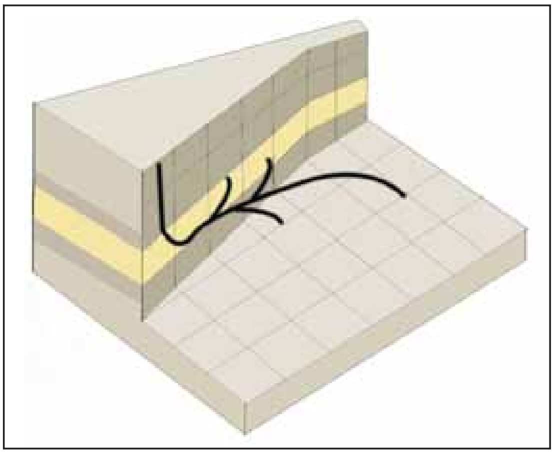


Figure 2 - Fishbone Well Profile

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

Seismic

X-rays enable doctors to 'see' inside the body and locate injuries without using a scalpel. Similarly, seismic enables scientists to 'see' inside the earth and locate potential hydrocarbon-bearing structures without using a drill bit[2].

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

In this way, hundreds of square kilometres with vertical depths reaching two miles (six km) or more can be imaged without incurring the time, financial and environmental costs of drilling several dry holes. With diligence, geoscientists will find 'bright spots' – the industry term for a potential hydrocarbon reservoir. Bright spots will

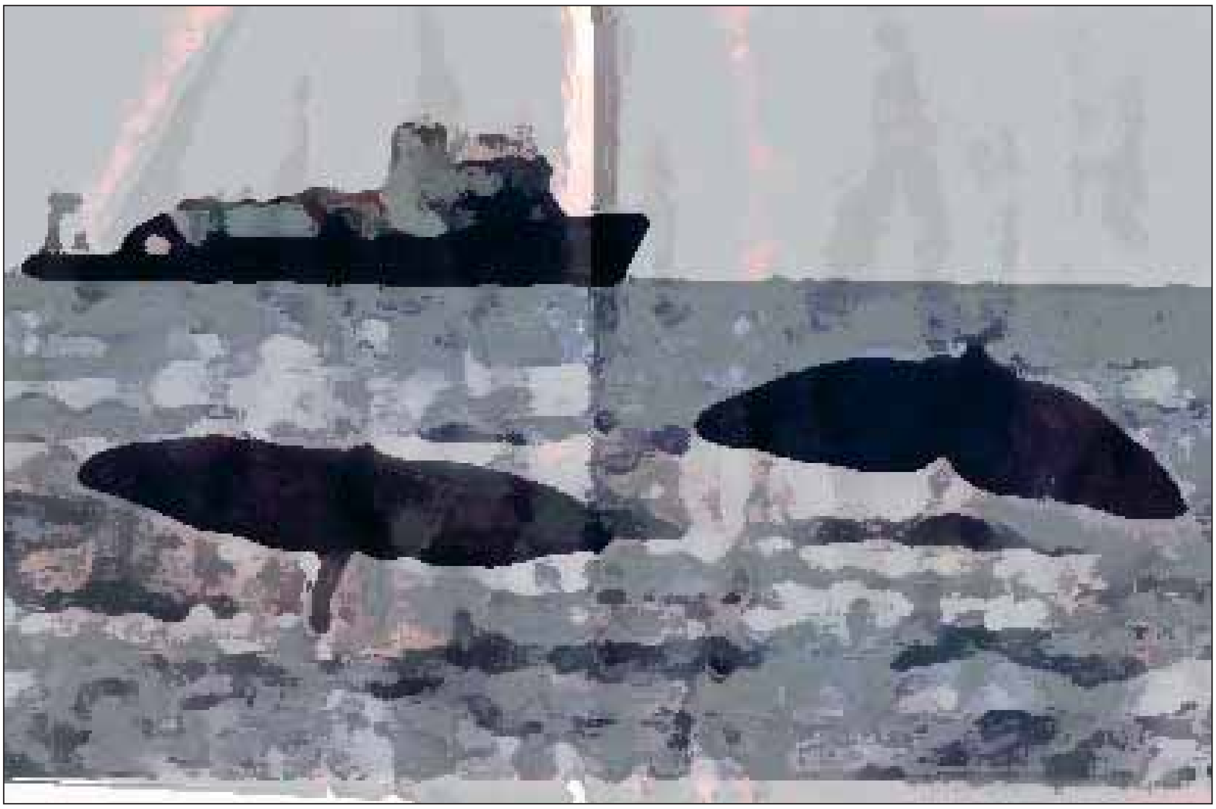


Figure 4 - EIA Minimises Disturbances to Animal Life

often form the basis of top drilling prospects. In this way, seismic allows the rapid and effective imaging of vast surface areas and the pinpointing of reservoir locations and properties. Drilling on bright spots is not a 'slam-dunk' as several International Oil Companies (IOCs) discovered in the early 1970s in offshore Florida. The bright spots were clearly there, but only a drop of oil was found.

Sound Waves

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

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

Pay-Per-View

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

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

Needle in a Haystack

Licensed acreage refers to areas where an oil company or group of oil companies has obtained exclusive rights to explore, develop and produce hydrocarbons. Clearly, finding oil and gas is a complex process with greater complexity added by offshore or remote locations and large unexplored blocks.

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

Environmental Regulations

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

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

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

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

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

Surface Tow

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

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

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

Brown and Green Fields

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

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

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

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

4D Seismic

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

Well Planning

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

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

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

Faster, Better, Cheaper

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

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

Blueprint

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

- The management of phased well construction service and supply processes to meet a desired timeline and objective
- Commercial aspects of contracts and pricing for well services and equipment
- Financial cover in terms of insurance and liabilities
- Legal conditions such as compliance with regulatory framework and outlining limits of responsibilities
- Design and operational aspects that cover detailed engineering drawings of well construction
- Health and safety considerations
- Environmental protection, and
- Political/cultural/linguistic aspects of the operations.

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

Essential Information

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

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

The well plan also includes such things as:

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

Targets

Targets usually refer to geological targets, which are the depths of formations that likely contain oil and gas. They can also refer to pre-determined casing points. Depths are expressed as vertical and measured depths. TVD, for our purposes, refers to a depth taken from a ninety degree straight line from the surface down to the depth of interest. The measured depth is the actual distance drilled. Other formations or markers along with their age and lithology, i.e. sand/shale, will be noted. The TVD is measured from the top of the target to the bottom height of the reservoir. When you read that a reservoir had 78 feet (25 m) of 'pay' or oil-bearing sands that refers to the vertical thickness of the oil and gas reservoir. 'First oil' refers to the first time at which production of a certain reservoir occurs[12].

In the Dark

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

Regulatory Compliance

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

Potential Hazards

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

• All wellhead components
• BOP stack and valves
• Accumulator
• Choke and kill lines
• Choke manifold
• Gas buster (or poor boy de-gasser)
• Drill string safety valves
• Standpipe manifold
• High pressure mud lines and systems (including cementing system)
• Drill strings
• Drill stem testing surface and subsurface equipment,
• Subsea well control equipment (if drilling from a floating vessel).

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

Formation Evalution Plan

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

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

Mud-Logging System

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

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

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

Examining Cuttings

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

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

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

- Well depth (depth)
- TVD
- Bit depth
- Rate of Penetration (ROP)
- Hook height
- Weight on Hook (WOH)
- Weight on Bit (WOB)
- Vertical rig displacement (heave)
- Torque
- Drill string rotation per minute (rpm)
- Mud pit volume
- Pump pressure
- Choke line pressure
- Pump strokes per minute (spm)
- Mud flow
- Total gas

Figure 5 - View of Cuttings Analysis

- Gas concentration distribution
- H2S concentration
- Mud weight in and out
- Drilling fluid resistivity
- Drilling fluid temperature
- Flow line
- Lag time, and
- Standard length[17].

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

Well Logging

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

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

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

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

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

Wellbore stability problems are detected with ultrasonic callipers from density or sonic LWD tools. Hole enlargement or washouts can be identified while drilling or during subsequent trips. This is beneficial as it helps monitor wellbore stability and allows adjustments to be made to mud weights or effective circulating density as required. Wellbore stability problems are confirmed using vision technology incorporating Azimuthal Density/Neutron viewer software, which provides density image and calliper data while drilling. The software also generates 3D images and calliper logs. Together, these offer easier methods of understanding wellbore conditions during drilling operations[21].

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

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

Pressure While Drilling

PWD tools are used to make accurate downhole measurements of:

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

Coring

Formation core samples may be taken and these are the most important way of examining formations and any oil-bearing strata. Cores are extracted by a ‘core barrel’ which usually takes 10 to 13 ft (3 to 4 m) lengths of the formation. As the core barrel is rotated, it cuts a cylindrical core a few inches in diameter that is received in a tube above the core-cutting bit. A complete round trip is required for each core taken. Much smaller and less representative cores may be extracted using a sidewall sampler in which a small explosive charge is fired to ram a small hollow cylindrical bullet into the formation. The bullets are tethered to strong retaining wires. When the tool is pulled out of the hole, the bullets containing the small core samples come out with the tool. Up to 72 of the small samples can be taken per trip at any desired depth. This provides positive real evidence of cross-flow, permeability and porosity. Laboratory tests are complex and can include fluorescence gas chromatography (TSF)[22].

Sampling and Screening of Cores

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

All core material is frozen and stored until it is returned to the lab[23].

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

Drilling to Total Depth

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

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

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

Setting Production Casing

If the operating company decides to set casing, it will be brought to the well and for one final time, the casing and cementing crew will run and cement a string of casing. This casing is 'floated' into the hole to take advantage of its buoyancy and relieve the rig from

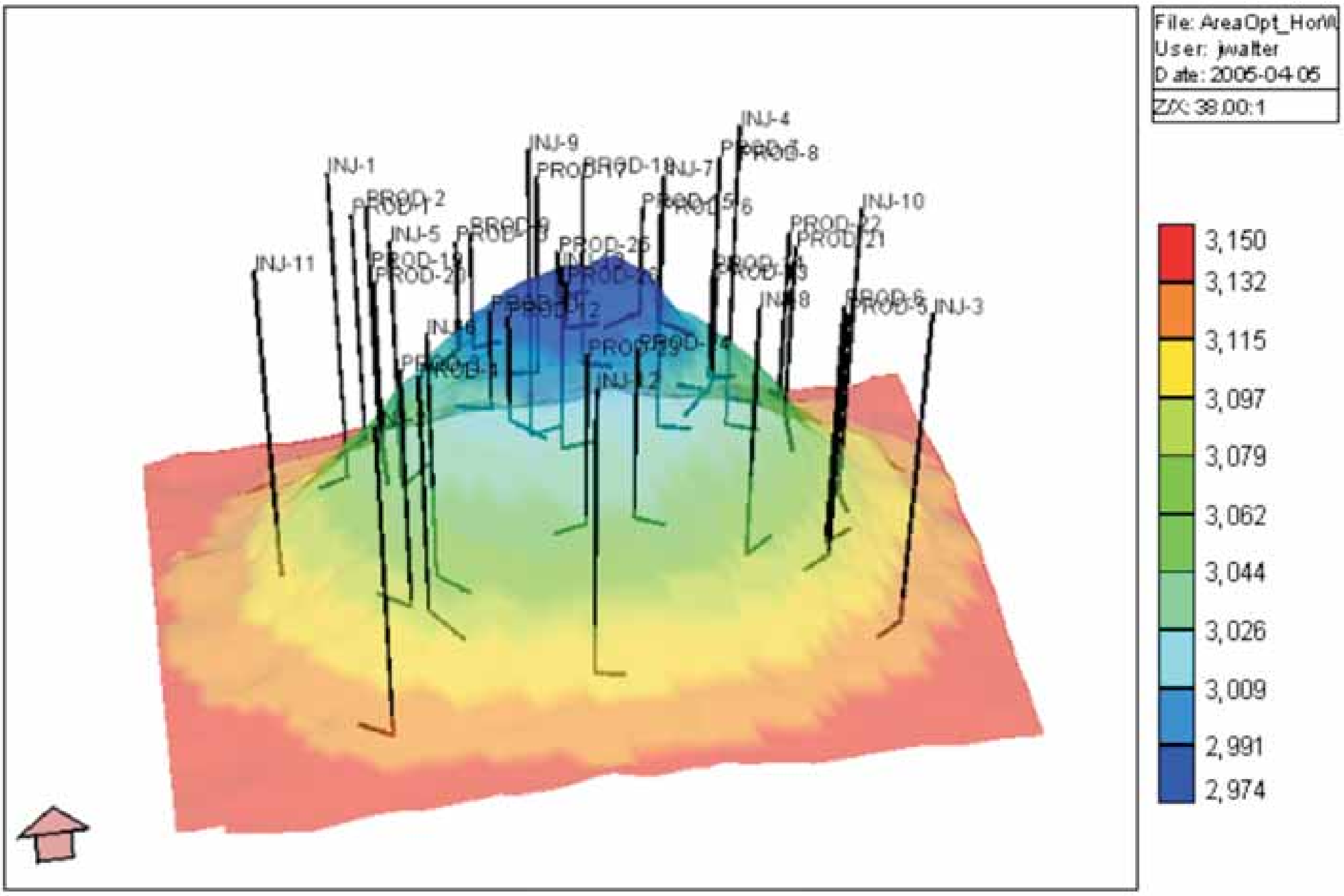


Figure 6 - Well Placement In Field Development

holding the immense weight of several thousand feet of large diameter steel pipe. A 'float shoe' seals off the bottom of the casing and keeps drilling mud from flooding the casing as it is runs into the hole. Usually, the production casing is set and cemented through the pay zone; that is, the hole is drilled to a depth beyond the producing formation and the casing is set to a point near the bottom of the hole. As a result, the casing and cementing actually seal off the producing zone but only temporarily. After the production string is cemented, the drilling contractor's job is almost finished except for a few final touches.

Cementing

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

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

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

Perforating

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

Acidising

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

Fracturing

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

Case Study: Geo-Steering

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

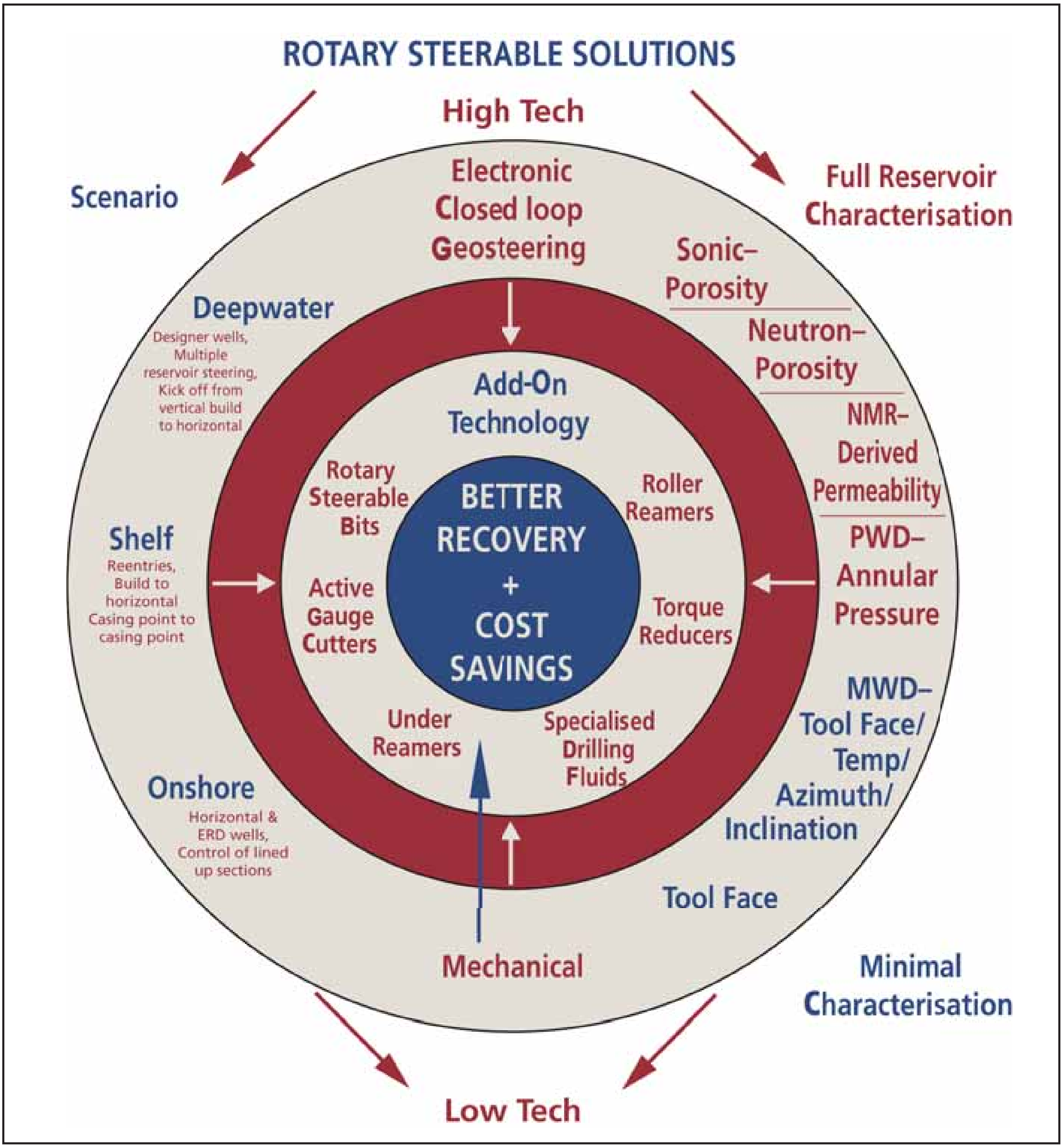


Figure 7 - Geo-Steering Technologies From High to Low Tech (EPRasheed)

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

Refining BHAs Through Offset Data

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

Rotary Steerable Technology

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

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

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

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

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

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

Often, however, a serendipitous use of real-time data pays dividends. Recently, an operator drilling in the shallow shelf waters of offshore Texas, encountered two extremely abrasive formations. On an offset well, each consumed ten drill bits to get through the zones. The logging requirements were not particularly sophisticated, but the service company pointed out that if the sections were drilled using its rotary steerable system with ultra high-speed telemetry, it could measure and monitor drill bit vibration thought to be the cause of the rapid bit-wear. The operator accepted the recommendation and with real-time vibration monitoring, was able to detect and analyse the circumstances causing bit wear. By adjusting weight-on-bit, rpm and mud weight, the operator was able to minimise destructive vibration and drill both problem sections with a single bit each, saving more than US $2 million from US $12 million Approval For Expenditure (AFE). The sophisticated solution costs more, but rig time was saved by eliminating eight bit change trips, and the added cost was more than compensated by the rig-time savings.

Add-On Technology

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

Case Study: Expandable Tubulars

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

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

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

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

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

Slimming Down

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

Contingency

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

Lost Circulation and Trouble Zones

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

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

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

Case Study: Digitalisation

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

5. Actual requirements will vary from country to country depending on the environmental or marine authority.

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

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

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

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

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

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

12. First oil is notoriously difficult to predict.

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

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

15. Idem.

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

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

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

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

20. Idem.

21. Idem.

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

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

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

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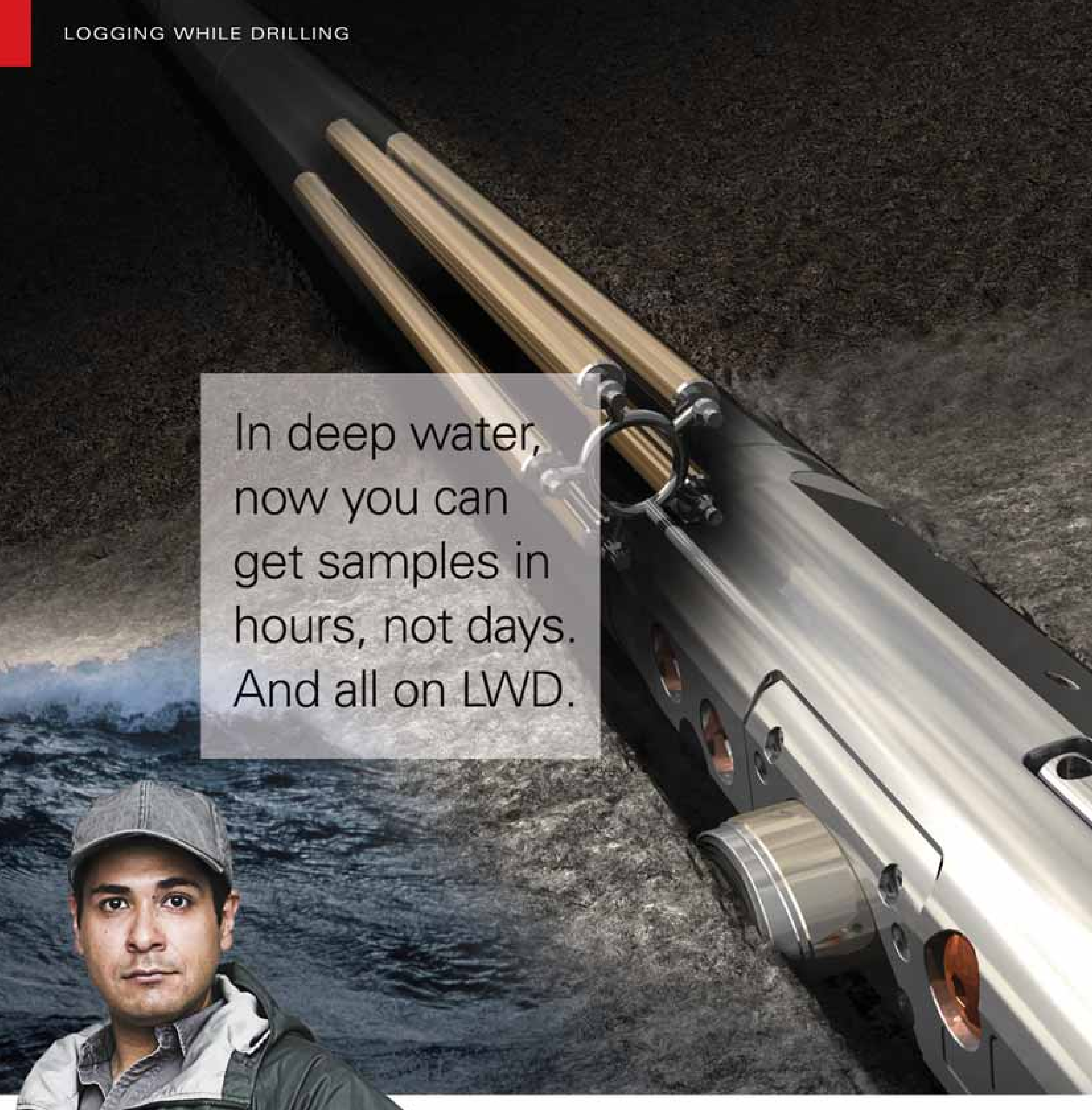

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