Finding Petroleum

Hurricane Energy - developing the Lancaster fractured basement field

ERC - how to estimate recovery from fractured reservoirs

How understanding the origin of fractures can help

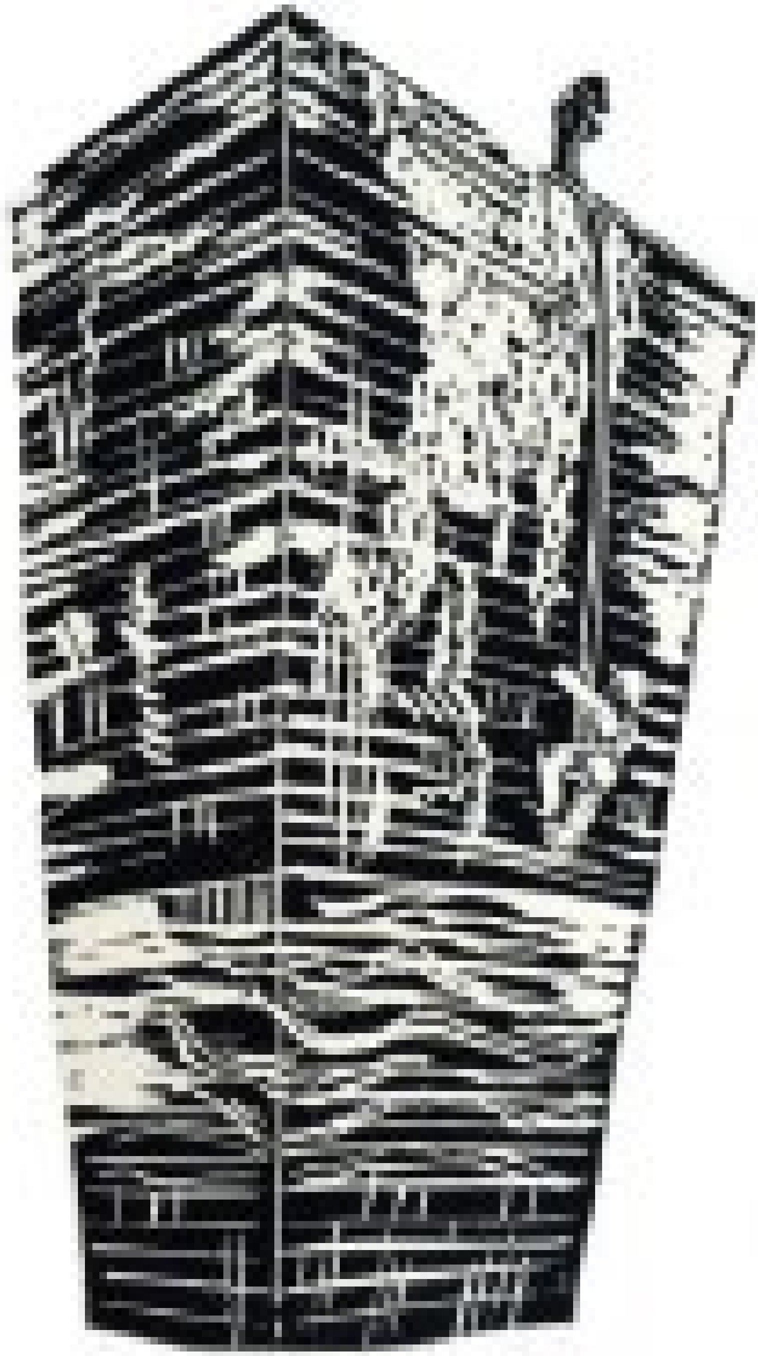
Combining stress (geomechanics) and flow simulations

Understanding Fractured Reservoirs & Rocks, London, January 23 2018

Special report

Understanding Fractured Reservoirs & Rocks

January 23 2018, London



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How to produce fractured reservoirs

When producing oil and gas from fractured reservoirs, it is helpful if you understand how fractures carry oil around the reservoir, so you can make sure you drill in the right place. It requires a combination of high resolution seismic, geological modelling, fractured related reservoir engineering, log data analysis, and perhaps also geomechanical understanding

BP discovered the fractured Clair field West of Shetlands in around 1977. For the next 25 years, the company was in a cycle of giving someone a year to do a study, then drilling an appraisal well, and then trying to work out what had gone wrong, said David Bamford, conference chairman, who had a long career working in BP.

"We never quite figured out which fractures were open, which were closed, which had any influence on flow."

The field finally began production in 2005 to 2006, some 30 years after the discovery, following a number of technology developments, such as seabed multicomponent seismic recording (which made it possible to look at fracture orientation and open-ness) and horizontal drilling.

Today, Clair is predicted to be still producing up to 2070. So we have "a field tricky to understand, tricky to get right, eventually got into production, it will have a 100 year history between discovery and end of production."

In the greater Clair area, there could be 13 to 15bn barrels in place. It could be Europe's biggest oilfield.

Worldwide, over 50 per cent of carbonate fields are fractured – far more fracturing than in clastic fields and basement. And carbonate fields make up an estimated 70 per cent of all oil reserves (because they account for much of Middle East oil).

Many people have studied fractured reservoirs over the past few decades, including David Bamford, who studied it in academia for 10 years before joining BP. But their knowledge has rarely been called upon by the oil and gas industry, perhaps, until now.

The Finding Petroleum forum in London on January 23 2018 looked at some of the advances to date in better understanding fractured reservoirs, including real case studies from two oil companies active in fractured reservoirs, Hurricane Energy and Gulf Keystone.

We also had advice from reservoir consultancy ERC Equipoise about how fracture understanding can be part of the reservoir engineers' toolkit; advice from consultancy Cambridge Carbonates about different ways that fractures form, and how this understanding can help predict what the fractures will be like; and a talk from Professor Brian Smart, former head of petroleum engineering at Heriot Watt University in Edinburgh, on how geomechanical models and reservoir engineering models might be tied together, and why it should be done.

This is a report from the Finding Petroleum conference "Understanding Fractured Reservoirs & Rocks, held in London in January 2018

Event website

http://www.findingpetroleum.com/event/2c77f.aspx

Many of the videos and slides from the event can be downloaded from the event agenda page.

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Hurricane's experiences in the Lancaster field

Hurricane Energy has drilled 2 horizontal wells in the Lancaster fractured basement field, West of the Shetland Islands, North of Scotland, and expects them to produce a total of 20,000 bopd based on well test results

Hurricane Energy, an oil and gas company based in Surrey, UK, has drilled 2 horizontal wells in the Lancaster fractured basement field, West of Shetland Islands, North of Scotland. It has drilled a total of five wells on the Lancaster field.

Based on well test results, it expects the two horizontal wells to produce 20,000 bopd in total, when the field comes into production in early 2019.

It is a reservoir which has been overlooked until now in the UK because of the abundant sandstone reservoir horizons, but also because until the mid-1990s there was insufficient technology to confidently exploit fractured basement reservoirs.

Robert Trice, CEO Hurricane Energy, first got interested in fractured reservoirs while working on the Clare field, also West of Shetland, while employed by Enterprise Oil in the 1990s (a company acquired by Shell in 2002). "It was my first insight into what could be sitting in the basement," he said.

The Lancaster Reservoir is on the Rona Ridge, south of the Clare field, west of the Shetland Islands, north of Scotland. The Rona Ridge is a relic of crystalline crust.

Geological background

Basement rock is defined as rock which is not from any kind of sediment, i.e. which formed from when the earth was a burning ball of magma and cooled down, 2.5 billion years ago. The initial joints (cracks) in the rock appeared from the initial cooling.

Then the basement below Lancaster was repeatedly buried under more layers of rock, and uplifted, over a long period of geological time. During this period of geological time the basement rock and the associated fractures was subject to periods of flushing by hot and cold water which would have deposited and removed minerals.

In the Jurassic era, the Kimmeridge Clay source rock was locally deposited on top of the basement

The continuation of the Atlantic rifting occurred into the upper Cretaceous. At this time the basement was buried to a depth where

Robert Trice, CEO Hurricane Energy

pasteurisation (killing bacteria) would have occurred, by heating the reservoir to above 80 degrees. If bacteria had been present in the reservoir they could have broken down (biodegraded) any in situ oil making the oil heavier. This is one of the reasons why Lancaster oil is lighter 38API than oil from neighbouring Clare field, Dr Trice said.

The Lancaster field sits on top of the Rona Ridge, a relic structural high, which at the time of the Jurassic period was a series of islands in a tropical setting. In the Oligocene / Miocene, the Rona Ridge uplift pushed the Lancaster structure rock up vertically by 1 to 1.5km.

"So you had an existing fracture network, uplift causing relaxation ion of the existing fractures, and being filled with oil," he said.

. The Lancaster trap was probably in place to take charge in the late Cretaceous, sealed by thick cretaceous muds, about 300m thickness, he said.

Planning the second well

The focus of the talk was on how Hurricane aimed to get a better understanding of the fractures and faults, before drilling its second horizontal well, "7z".

The 7z well was planned to be drilled to the north of the first "6" horizontal well, aiming to penetrate a series of "seismic scale" faults (large enough to show on seismic). It was expected to drill through reservoirs of average porosities of 3.6 to 4.4 per cent. It was expected to repeat the success of the first horizontal well, with flow rates of around 9,800 and similar API of oil. It did turn out to be a good well, as explained later.

But in order to put the drilling plan together, "we had to be confident we felt we understood what was making the reservoir work," Dr Trice said. In other words, the company needed a working reservoir model.

The three most aspects for understanding a fracture system were thought to be the fluid pressure and how this compares with the lithostatic pressure (gravity forces from the rocks above); the magnitude and orientation of the mean stress gradient; and the fracture connectivity.

Faults were seen as preferential drilling targets. Long faults are "generally associated with better reservoir properties," he said. Also, "areas where there is good connectivity of faults are better than isolated faults."

Hurricane also wanted to drill at least 200 to 300m into the basement, because rock towards the top of the basement can have different properties, being affected by dissolution (fluids from above dissolving it).

Pressures and drilling

Understanding the subsurface fluid pressures is very important. For drilling, it is important for safety and managing drilling muds, ensuring the drilling mud pushing into the reservoir has a higher pressure than oil pushing out into the well. The fluid pressure also controls how liquids will flow into the well. Fractured reservoirs can show a variety of aerial pressure regimes if associated with pressure sealing faults

The first vertical well was drilled on the assumption that the pressure increase to the subsurface would be hydrostatic, i.e. the same increase in pressure as you would see with a vertical column of fluid, caused by gravity force of the fluids above. This assumption was based on data from other wells in the region, and the geological model.
For the first well, the company was concerned about the drilling mud being lost into the frac-

tures, so it used a 'shear splitting' mud called DRILPLEX, which is designed to block up fractures. The disadvantage of this mud is that by blocking up the fractures, it makes it hard to do well tests or logs.

The results of well logs showed no signs of overpressure in either the basement or overlying clastic rock. "That gave us real confidence in the mud weight and the pressure gradient," he said.

Using this understanding, the second vertical basement well "4Z" was drilled using an experimental tool which made it possible to drill 'balanced' rather than 'overbalanced' (i.e. with the weight of the mud exerting a greater force pushing reservoir fluids back into the reservoir, than reservoir forces pushing on the well to get out).

The drilling was done with a mud with no particulates in it. This has the benefit (from a logging point of view) that it does not build up a 'mud cake' along the well wall. It is basically salty water (a brine). Brine proves "fantastic for data acquisition" but can make it tricky getting tools to the bottom of the hole due to the brines poor lifting capacity resulting in drilling cuttings collecting at the bottom of the borehole

For subsequent drilling, Hurricane anticipates that there will be a normal hydrostatic pressure regime in the reservoir, but no extra "oomph" from overpressure carrying fluids into the well, he said.

Stress models

Understanding the stresses and stress direction was considered important in understanding the fractures. Before drilling, there was a theory was that fractures aligned with the stress direction are going to produce more oil.

However studies made after drilling did not support that idea. "Fractures of a variety of orientations flow," he said. "Some of these large aperture fractures which flow have a different orientation."

The indications are that the maximum horizontal stress in the reservoir is NE SW orientated, based on borehole breakout data (analysing the direction where the borehole is breaking into smaller pieces horizontally during drilling).

Schlumberger was contracted to develop a number of stress models, making a map of joints (gaps in the rock layers) which it could see on imaging logs (digital images taken down hole), and showing how they were orientated. It concluded that again the maximum horizontal stress is NE SW direction.

Dr Trice explained that Hurricane has no definitive stress model for the reservoir but has a working model which it is currently challenging with recently acquired data.

Modelling fractures, faults and joints

The fractures, faults and joints in Lancaster occur at a number of scales. There are micro fractures, defined as having a trace length less than the diameter of the bore hole, and joints classified from borehole imaging as fractures with a trace length at least as long as the borehole diameter.. Then there is large "seismic scale" faulting, discernible from seismic. Between the two there are characteristics of the fracture system which can be discerned from dynamic well testing, Dr Trice said.

Large scale faults are an important target for exploration appraisal and development. The company wanted to be confident in its fault maps.

The first well was based on a very low density fault map. But this map became richer as work progressed. "I asked my geophysicist to create a map which 10 geophysicists would agree with. In other words, every fault on there really had to be there. We could potentially drill a well through it."

"As we add more data and integrated it, the fault pattern became more confident," he said.

Data gathered during the drilling, and in subsequent well logs, was also used to further develop the fault map.

Both the seismic and the horizontal well logging indicated that the faults are predominantly subvertical (close to vertical).

A map was also made of the joints within the reservoir. The joint classification can be made in a number of ways, such as the orientation (going NE SW), cross joints, orientation at high and low angle, and large aperture joints (over 2cm). A greater than 2cm aperture is the size associated with turbulent flow, and also Karst type reservoirs.

The study showed that there was not any increase in the number of joints when close to faults, or within "fault zones", as some studies of fractured reservoirs elsewhere show.

The bulk porosity (void fraction) is about 4 per cent. Bulk porosity is interpreted as being related to fractures and includes fractures enhanced by dissolving (dissolution) of the rock,

Log studies

Well logs were widely used to get a better understanding of the fractures, faults and joints. It helped that the company's CEO, Robert Trice, had a background as a petrophysics, so had a great deal of experience working with well logs to 'constrain' or understand the limits of what might be happening.

The most important data proved to be the PLT (production logging tool), which can provide information about the formation fluids.

The data can be integrated with high resolution gas chromatography (analysing gas samples for their content). It gives further information about the permeability and fluid types.

The company also took sidewall cores (rock samples taken from the side of the well bore) while drilling. Before taking the cores, it used digital imagery (known as 'digital image logs') to identify a good place in the sidewall to take the core, and make sure it was not trying to take a core from within a joint.

The position and depth of a given sidewall core is established by running an UBI (ultrasonic borehole imager). Petrophysical analysis is undertaken on the laboratory on the SWC's.

With well logs it as possible to confirm the presence of fairly large aperture fractures, for example one with 40cm diameter, flowing oil. "These things are quite common in the basement and indicates there's something helping the fracture system other than mechanical failure," he said.

Another useful piece of evidence about fracture size was from rock samples which came to the surface stuck to the drillbit. Dr Trice showed one photograph of a rock sample, which looked like a cobble from a beach, worn down by water. It had been choked in a fracture, and indicates that the fracture aperture must have been wide e enough to hold it.

Micro fractures can be clearly seen on the image logs, and by analysing them when "captured" by SWC's itis possible to understand the diagenetic processes (how the rock was formed) through thin section analysis
The NMR (nuclear magnetic resonance) log

can be used to get porosity data.

Dynamic tests for microfractures

There are two dynamic (change) tests which could be used to understanding microfractures – well tests and analysing tides in the water above.

The well test involves shutting the well in and studying how the pressure changes over time. The increase in pressure happens at different rates, due to two different systems – the microfracture oil feeding into the joint system, and the oil feeding from the joints into the well bore.

Tidal data also proved useful. Over the tidal cycle, Lancaster is compressed by about 1psi, and analysis indicates that two thirds of the fracture system is compressing. "We conclude that micro fractures are most likely to be the cause of that compression," he said.

Putting into a model

All of the fracture, fault and joint data was put together in a model, which could then be used in a reservoir simulator, to see how fluids might flow, and then used to plan the drilling path.

Consultancy Golder and Associates was brought in to put together a discrete fracture network (DFN) model, by consultancy Golder and Associates.

The model was run in a flow simulator, which showed that the "regional joints and faults are the main contributors to the flow from the fracture system," he said.

Drilling 7z well

The 7Z horizontal well was drilled based on this fracture network model and the interpreted seismic,

Based on the model and simulation, the well was expecting to encounter 11 fault zones, and produce at a similar rate to the 6 well, perhaps higher rates.

As the well was drilled horizontally through the faults, the path dropped, finishing up 70m below the start point vertically.

The average fault zone width for this well was 49m, just above the 40m average for the field. Porosities for the reservoir was 3.8 per cent, slightly lower than the field average of 4 per cent. The regional joints ran NE SW, supporting the reservoir model.

"From the drilling data, it looks like we've got a nice reservoir," he said.

Ultimately the well flowed at 15,000 bopd in the well test, with flows limited by surface equipment, and with a high productivity index (a measure of how easily fluids flow into the well).

"So, a very favourable well. The well was suspended as a future producer," he said.

Putting the well result together with other well results gives you new conclusions about the fracture system. It showed that "fracture intensity does not appear to be controlled by any of the element you would normally expect, [such as] distance to fault zones, or distance to fault zone boundaries, reservoir depth or relative distance to the top of the basement," he said. "It appears that the fractures are just there."

Future development

Hurricane now plans to tie the 2 horizontal wells to an FPSO (a floating production storage and offloading vessel). It aims to keep production levels from both wells at 20,000 bopd, to avoid reservoir damage. Over the first 6 years it expects to produce 37m barrels.

It plans to do interference tests on the wells to try to better understand the dynamic properties of the reservoir.

After that, it will be able to plan a second phase of field development, with more wells, and wells further away.

Dr Trice believes that the likelihood of water breaking through into the wells is low, because the water zones are believed to be some distance away from the wells. But also, it is keen to keep production rates down low enough to avoid water production. "We know high rates bring in water, and we want to avoid that."

If there is water production, the FPSO is able to handle it, and the company's environmental submission allows treating for water onboard and disposal over the side, he said.

Shaikan - Early life insights into a giant fractured carbonate field

What has been learned over the past five years of production from Shaikan, a giant fractured carbonate field? This talk was presented by Kathy Kelly, subsurface manager – Gulf Keystone Petroleum

The Shaikan Field lies in the Kurdistan Region of Iraq, in the north of the country, within the Zagros fold and thrust belt. This talk describes what has been learned over the past five years of production from this giant fractured carbonate field.

The Shaikan Production Sharing Contract (PSC) was signed by Gulf Keystone Petroleum International (GKPI) in November 2007. The licence covers 280km2 and lies within the foothills of the Zagros Mountains approximately two hours by road from Erbil, the regional capital, and two hours from the Turkish border crossing to the northwest at Zakho.

The SH-1B well was drilled in 2009 and discovered oil in Cretaceous, Jurassic and Triassic fractured carbonate reservoirs. Acquisition of 3D seismic data and drilling of five appraisal wells proved a significant oil column of 800 m in the Jurassic alone, over an area covering 135 km2. The field was declared commercial in August 2012.

A Field Development Plan (FDP) was submitted to the Ministry of Natural Resources (MNR) in January 2013. Following approval in June 2013, two production facilities each of 20,000 bopd nameplate capacity were built and commissioned, and four additional wells were drilled. The field reached a production milestone of 40,000 bopd in December 2014.

Nine wells are currently on production and the field has produced over 43 million barrels to date from the Jurassic reservoirs. All production wells are flowing dry oil naturally with no free gas or water.

Kathy Kelly, Sub-Surface Manager, Gulf Keystone Petroleum Ltd

At the point of approval of the 2013 FDP, significant reservoir related uncertainties were recognised. These included; fracture STOIIP, vertical and lateral connectivity, fluid properties and variability, long term well deliverability, drive mechanism, aquifer influence and matrix contribution to recoverable reserves.

Continuous monitoring of downhole pressures in all of the producing wells has provided an invaluable dataset which has been used to calibrate dynamic field models and address some of the key uncertainties identified above.

An extensive programme of desktop, laboratory and field-based studies has been carried out with the aim of improving characterisation of the Shaikan reservoirs and fluids. This knowledge has been brought together in a series of discrete fracture network sector models which have been calibrated to single well drill stem and production tests, multi-well interference tests and long-term production data.

Calibration of these models to the five years of Shaikan production history has provided an understanding of the drive mechanism for the Jurassic reservoirs and provided confidence in the estimation of connected STOIIP, fluid properties and future well performance.

With 45 million barrels of oil produced to date, Shaikan has produced only 8% of its estimated 2P Jurassic recoverable reserves. A programme of investment is planned which is aimed at maintaining Jurassic production in the short term with further expansion in the medium to long term.

Plans to develop the Triassic reservoirs are under investigation and the Cretaceous could yield additional, as yet commercially unproven resource potential.

Although Shaikan is in the infancy of its production life, the lessons that have been learned during this early phase of development provide a valuable foundation upon which to build future expansion phases.

This is the published abstract of the report – we are not able to publish a report of this talk in our usual style due to restrictions from Kurdistan government and project partners on what can be published

ERC – how to estimate recovery from fractured reservoirs

Shane Hattingh, principal reservoir engineer for reservoir consultancy ERC Equipoise, presented the 'toolkit available to reservoir engineers to help them get a better understanding of fractured reservoirs'

The reservoir engineer's role is to try to understand how fluids flow in a reservoir, so work out a plan to maximise production or ultimate recovery.

Fractures in a reservoir change its producing properties in two ways – firstly in the way they hold oil themselves (so change the porosity), and secondly in how they change the way oil flows through the reservoir, in terms of changing overall permeability and the transport functions of specific fractures (conductivity).

Separately, the reservoir 'matrix' (rock body) of a fractured reservoir also has a porosity and permeability like a non-fractured reservoir.

So to understand a fractured reservoir, you need to understand both the matrix and the fractures separately. This adds a layer of complexity to the work of understanding the reservoir.

Shane Hattingh, principal reservoir engineer for reservoir consultancy ERC Equipoise, presented a number of "tools" which reservoir engineers can use to understand flow through the fractures and matrix, including analogues, decline curve analysis, numerical simulation, and analytical methods. Also understanding the different stages of pressure depletion, using different equations, and ways to understand porosity.

It is common for the fractures to have a low porosity themselves (i.e. actually carry a low amount of oil, or take up a low percentage of overall rock volume), but be very useful for conductivity (ability to carry fluids).

Shane Hattingh, Principal Reservoir Engineer, ERC Equipoise

Ultimate recovery

An important calculation reservoir engineers make is the estimated ultimate recovery from a reservoir. Reservoir engineers put together a "development plan" for how to develop the field – the big question is how well that development plan addresses the recovery mechanism.

This is a function of the gross reservoir rock volume, the "net to gross" (amount of pay footage divided by reservoir interval thickness), the porosity, saturation, and the fluid properties. It can be calculated either for a field average value, or at a geocellular level.

The recovery factor is a single number, based on hydrocarbons which will be produced (or recovered) divided by all the hydrocarbons in the reservoir. This is linked to your production forecast.

All of those factors have uncertainties, and for fractured reservoirs there is a 'doubling up' of uncertainties, because you have uncertainties for the reservoir rock itself and for the fractures in it.

There are cross-relationships between the factors, for example where you consider that the reservoir matrix 'net to gross' figure might be dependent on the fracture spacing and therefore the fracture porosity.

It might be more useful to look at recovery through a production profile (your expected rate of production of the lifecycle of the reservoir) rather than your overall recovery, because the field will only be in operation when the production levels make it viable. By looking at production rates, rather than overall recovery, you are forced to look at all of the elements which influence the production profile, the reservoir and aquifer properties.

Then there are a number of 'recovery mechanisms' through which oil is produced from the fractures, more and different mechanisms than there are for non-fractured reservoirs. These are explained in more depth below. Some of these factors are time dependent.

Four tools which reservoir engineers have to help them estimate recovery are analogues, decline curve analysis, numerical simulation and analytical methods.

Analogues

"Analogues" is basically saying, show me a similar reservoir and what its recovery factor was.
So it can be helpful if you look for a field which is similar to yours in terms of extent of fracturing and wettability.

But analogues are hard to find for fractured reservoirs, since there is not a great deal of published literature, and recoveries can range from less than 10 per cent, to more than 70 percent, he said.

"Our approach to analogues is not to try to find analogues on recovery factors, but rather to try to focus on the building blocks which go into the production profiles, that ultimately lead to those recovery factors," he said.

Decline curve analysis

An equation is used by reservoir engineers for all kinds of reservoirs, based on theory for non-fractured reservoirs, about how production rates are likely to decline.

"A lot of work has been done to try to establish decline curve equations which apply to fractured reservoirs," he said. One approach is to see how fluids flow from a fracture in a core plug in a laboratory, and then scale it up to field wide level.

Decline curve analysis is usually only used very late in field life, rather than being used to plan a field development from the early stages.

Numerical simulation

Numerical simulation is the reservoir engineers' most powerful tool, basically constructing a dynamic simulation model of the fractured reservoir.

The first stream of work is to try to build a 3D model of the fracture network, which includes the main parameters for including in fluid flow equations, including porosity, “net to gross”, saturation and permeability.

The other stream of work is to characterise the rock matrix, which is done in the same way as for a non-fractured reservoir, and also create a 3D model with that.

There is also a need to get geometric information about the matrix blocks. They are ‘idealised’ into shapes like squares, rectangles and columns. This needs to be done in order to solve the flow equations.

“The real challenge is merging this lot together,” he said. This also requires understanding how oil and gas moves out of the matrix into fractures.

Once it is all done you can run fluid flow equations for the whole system, the basis of the flow simulator.

Overall, numerical simulation is mainly useful when you have enough production data to calibrate your model through history matching. “It has limited usage in the pre-development stage - for all types of reservoirs, but particularly for fractured reservoirs,” he said.

The oil recovery from the matrix is determined by physics or chemistry, and the simulator can’t tell you what it is, you need to know that before you run the simulator.

Fractured reservoirs have many more physical processes that take place, so you have many more degrees of freedom. “You need to work out those recovery mechanisms are so you can instruct the simulator,” he said.

The simulator can be a powerful tool in the early stages of development, in that it is a tool you can use to bring the components together and try out production profiles and other hypothesis about the field, and see what is sensitive to what.

Analytical methods

To use analytical methods you first need to analyse what sort of reservoir you have.

The modelling method will be different, depending on if your matrix poro-perm is high or low, and whether the fractures additionally provide permeability.

This idea maps to the 1999 classification of reservoirs into Type 1, Type 2, Type 3, Type 4 by Nelson.

Having an idea of the ‘type’ of your reservoir can help you search for analogues.

Another question is whether you expect pseudo steady state conditions to prevail in the matrix blocks, and where dual porosity behaviour is evident.

Example

Dr Hattingh illustrated how this could work using a real example of a reservoir with thick carbonate fractured limestone, with karstification (caves) at the crest.

The fractures are on a 2m scale, the matrix porosity and permeability are reasonable. There is a fairly thick oil column with light oil, and a very strong aquifer. All the wells are at the crest of the field.

The monitoring wells showed that the reservoir has a strong aquifer pushing oil into the reservoir through gravity, and quite strong viscous forces driving oil through the fractures, all leading to a recover factor of 50-80 per cent.

The matrix blocks were initially completely saturated by oil. As water comes in contact with the matrix block, it will expel oil from the matrix, increasing the recovery factor. However “that doesn’t always happen, sometimes the pressures are working against you, with a capillary pressure tending to prevent water moving into the block,” he said.

Whether water expels oil from the matrix depends on the wettability of the rock, whether you have a ‘water wet rock’ which absorbs water. You need to know which type you have.

In this example the wettability, as determined from core analysis, could be described as “mixed”.

Stages of pressure depletion

A reservoir will go through a number of stages of pressure depletion as it is produced.

In the first stage of pressure depletion in a field with no water injection the drive mechanism is expansion of the undersaturated oil.

The second phase starts when the pressure drops below the bubble point pressure, where gas comes out of solution in the oil. The amount of gas which comes out depends on the difference in pressures and the size of the matrix block. When gas comes out of solution it will expand before becoming mobile.

After that, you get two phase flow coming out of the matrix, and it is difficult to work out what the recovery factor will be, because it depends on the gas and oil relative permeability.

Another factor is if gas goes into the matrix and pushes the oil out. The capillary pressure will tend to keep gas out of the matrix block, but the gas pressure will push it in. You have an interfacial tension between the two. There may also be gravity issues and molecular diffusion.

The simulation model needs to know which of the processes are taking place.

Getting the right equation

When working out how fast the fluid will flow, one equation which can be used is Darcy’s law, which covers the relationship between velocity of fluid and pressure gradient through a porous medium, with a constant in the equation equal to permeability over viscosity. “We know that equation works because we can do tests on core plugs in laboratories,” he said.

The question is what equation of motion should be used to form differential equations for flow through fractured networks.

Reservoir engineers have recognised there are analogues between fracture networks on a large scale and a porous medium on a microscopic scale, although the scales are different by about a billion to one. If Darcy’s law can be used on a small scale, perhaps it can be used on a fracture network on a large scale. “Indeed it appears to be the case, we know that from interpreting drill stem tests,” he said.

If Darcy’s equation is used on fracture networks, it saves having to solve a full set of equations in the simulator. You can use the same set of equations for fracture networks and for the matrix rock.

Then the question is how the permeability can be calculated for a fracture network.

An equation often used on fracture network says that the permeability of a single fracture is equal to the width (aperture) squared and divided by 12, and also divided by a calibration constant C. That equation comes from the Navier Stokes equation, the most general of all fluid flow equations, used to model air flow around buildings and over aircraft wings.

If the fluid flow is in ideal conditions, C = 1. These are steady state laminar flow, single phase, incompressible, viscous fluid, through regular slits (constant width), under isothermal conditions, subject to viscous forces, no gravity and no capillary pressure.

That never happens in real life, and everyone recognises that, but it makes a starting point.

The main reasons for difference are the roughness of the fracture surface (rugosity), the flow pattern of the fractures (tortuosity), and the continuity of the fractures. If you have quite a lot of rugosity, the aperture is changing inside the fracture.

C is typically 5 to 50 in real life. So if you just apply this equation without working out C, "you'll overestimate your permeability by quite a large amount."

Another way to estimate permeability is with a pressure transient analysis of a drill stem test, where the reservoir is shut in to see how fast the pressure downhole will grow, due to fluids flowing towards the well which do not get produced.

So now we have a relationship between permeability, fracture spacing, size of aperture, and porosity of the fractures.

Porosity

Fracture porosity is extremely hard to quantify, he said. Traditionally image logs are used (downhole digital photos). Alternatively it can be analysed from fracture spacing and fracture aperture data, in a discrete fracture network model.

Fracture spacing can also be taken from image logs reasonably easily. However measuring fracture aperture is very hard to do from any kind of logs.

One idea is to use an independently estimated parameter like permeability, and that can be used to at least confirm the range of uncertainty in the fracture porosities.

Conclusion

Dr Hattingh concluded by making the general observation that the development of fractured reservoirs is often most successful in cases where the development is done cautiously in a phased pattern, allowing operators to gain understanding of the recovery mechanisms before embarking on further phases. Conversely, developments that carry a greater risk are those where the operators have launched into full field development plans without gathering data and understanding mechanisms of recovery process.

Cambridge Carbonates – fracture systems in carbonate reservoirs

Fractures in carbonates can have many origins – understanding the origins can help you understand the fractures, said Jo Garland of Cambridge Carbonates

Understanding or predicting fractures is very important in carbonate reservoirs, since >50% of fields are fractured. However, not all fractures have a tectonic origin, so it is important to recognise the mechanisms responsible for fracturing as this will have an impact on reservoir geometries and quality.

Jo Garland, consultant geologist and director with Cambridge Carbonates, presented the four key origins of natural fractures in carbonate rocks, and provided insights into how to differentiate these.

The four mechanisms responsible for fractured reservoirs included tectonic processes (structural fractures), karst collapse (following the dissolution of soluble rocks and cave collapse), evaporite collapse (dissolution of evaporite bodies and subsequent collapse and fracturing), and fracture-related dolomites (where Mg-rich fluids move upwards along fracture pathways and dolomitise the surrounding host rock, sometimes known as hydrothermal dolomites).

Tectonic fractured systems

Tectonic fractured systems occurs in several different structural settings. These include compressional settings (i.e. thrust and fold belts and foreland basins, such as the Zagros Mountains or South East Mexico); salt tectonics, such as in the North Sea and in South East Mexico; and transtensional settings. In any of these settings, both Type 1 and Type 2 fractured reservoirs can develop, depending on the original depositional facies.

Tectonic fractures are predictable in a statistical sense, and all scales of fracture are important. Microscale fractures should not be overlooked, as they can be important for storage and production. They can also have role of connecting the larger, productive, fractures together, and could be regarded like the matrix. Bed thickness also has an impact on fracture density and spacing – commonly thicker beds have less fracture density than thinner beds, she said.

The distribution of fractures can often be linked to the underlying geology. For example, if there is a deeper lineament (i.e. horst blocks, or half grabens) underlying the reservoir, compressional tectonics may result in the development "fracture corridors" as the competent fractured reservoir is jostled over the irregular topography – this phenomenon is seen in both the Tampico Misantla Basin in NE Mexico, and also in the Gachsaran and Bibi Hakimeh fields in Iran. This can be compared to compressional tectonics associated with salt, where fracturing is more closely tied to folding of the anticlines (such as in the Sureste Basin in Mexico).

Type 1 and Type 2 tectonically fractured reservoirs were discussed, with the Kirkuk field (Type 2) and Ain Zalah field (Type 1) given as examples. In both fields, fractures were critical for storage (porosity) and production (i.e. permeability), but only in the Type 2 reservoirs was hydrocarbon storage also in the matrix.

Dr Garland commented that from published data, it was clear that the percentage of porosity provided by fractures in tectonically fractured carbonate fields is generally <1%, and commonly less than 0.5%. This is important, particularly when evaluating Type 1 tectonically fractured reservoirs, as there is no matrix porosity contribution.

Karst fracture and breccia systems

Karst fractures and breccias are formed through the collapse of caves. These palaeocave systems formed during prolonged periods of sea level lowstand (i.e. exposure), and therefore can be predicted in a sequence stratigraphic framework. This results in reservoir geometries very different to those developed in a tectonically fractured carbonate reservoir.

Fracture and breccia systems created through karst collapse have different properties depending on their location in the palaeocave network. Within the caves themselves, chaotic breccias may be more common, since these represent break-

Jo Garland, consultant geologist and director with Cambridge Carbonates

down material from the cave walls and roof. On the other hand, crackle breccias and considerable "in-situ" fracturing are more common in the cave walls and ceilings. Collapse breccias, particularly if they represented stacked or nested caves, can form thick dual porosity reservoirs, which are highly permeable and stratiform.

Rospo Mare field, offshore Italy, was given as an example of a highly productive karstified reservoir. The karst is recognised on seismic (sinkholes), and core and well logs indicate a 600m thick karstified reservoir. The reservoir is compartmentalised, with the upper reservoir having dominantly vertical fractures, and the lower reservoir having predominantly horizontal fracture and breccia zones. Fracture density from cores is approximately 15 per metre. The field was developed using horizontal wells, with well production up to 8000BOPD.

Dr Garland commented that often there is a highly connected pore system, which you can identify during drilling when you see high volume mud losses, and bit drops. Wireline tools (caliper and density logs in particular) are used to recognise large connected porous zones; however, if is important to note that these can be very heterogeneous reservoirs, both vertical and laterally. Well productivity can be quite unpredictable: it can be 50,000 BOPD, or wells nearby may not flow at all as they have not encountered the karst network.

Evaporite collapse fracture and breccia systems

A well-known fracture mechanism in the Permian carbonates in Europe is the development of evaporite collapse breccia systems.

These are formed where the original depositional facies consist of interbedded limestones and anhydrites (anhydrous calcium sulphate), and the anhydrites are exposed to rainwater percolating through. The water converts the anhydrite to gypsum (calcium sulphate in its hydrated form), which incurs a 64 per cent increase in volume. This growth in volume puts pressure on the limestone above, and causes it to break up or "brecciate".

The gypsum continues to dissolve in the meteoric water, leading to more collapse in the overlying and interbedded limestones. The anhydrite layer is now a void, and the limestone above fractures or falls into the void. The anhydrites could have originally been 100m thick, they end up as little as 5cm thick.

There are examples of this in the "Zechstein" shelf edge of the North Sea, which can be seen in an outcrop in Durham, North of England.

The evaporite collapsed breccias are highly porous and permeable. They probably count as Type 2 or Type 3 reservoirs (where fractures assist with permeability). The reservoirs are typically 10-15m thick, rather than hundreds of metres (as with karst reservoirs), with fractured rock overlying, and breccias (chunks of different types of rock) below. "You model this very differently to any tectonically fractured carbonate," she said.

Fracture related dolomite bodies – hydrothermal dolomites

The fourth mechanism Dr Garland showed was fracture related dolomite bodies, often known as hydrothermal dolomites. This mechanism occurs where hot, Mg-rich fluids move upwards through fractures, dolomitising the surrounding host carbonates. Hydrothermal dolomites can add additional matrix porosity to what would traditionally may be considered a fractured reservoir, thus creating a Type 2 reservoir (where porosity is additionally provided by the matrix).

Fracture related dolomites cross cut stratigraphy, following fracture and fault networks, but their geometry is also a function of original facies permeability – if the original depositional facies was permeable, then this was a focus or fluid pathway for the Mg-rich fluids. Asked by an audience member how common these reservoirs are, "The more we look for [this mechanism], the more we see it these days," she said. "It occurs in all types of tectonic settings."

Known dolomite bodies are up to 6.5km wide (generally around 1km wide), but can be 10's km in length, following complex fracture patterns. Commonly, the sheets and fingers of dolomite, extending away from the main feeder faults, offer the best reservoir quality.

Dr Garland commented that fracture-related dolomites can be spotted through "very careful diagenetic studies", and these reservoirs need to be modelled both using the structural evolution, and depositional architecture, as there is often a close link to primary depositional architecture.

Predicting fractures

So when you are asked to evaluate a thin section of rock, you need to establish the mechanism for creating the fractures.

Tectonic fractures are predictable in a statistical sense, and can be modelled through understanding the structural evolution. Karst fractures can be predicted in a stratigraphic framework, can occur over thick intervals, but their fracture pattern is semi-random within the collapsed breccia zones. Evaporite collapse breccias and fractured intervals are thinner and stratigraphically controlled. Hydrothermal dolomites can be modelled within a structural framework, and with understanding the existing stratigraphic architecture.

There can be multiple fracture mechanisms, for example breccias overprinted by tectonic fractures.

"The only way to unravel this is by careful diagenetic studies" (looking at how the rock was formed from the sediment), with any core or seismic data you have available. "We shouldn't assume that fractured carbonates are created simply by structural mechanisms", she said.

Combining stress and flow models

The changes in stress state in a reservoir rock can have a large impact on how the fluids in a reservoir flow, and induce ground movement. The stresses change as production reduces pore pressure. How can we better combine stress models and flow models? I.e. Rock Mechanics and Reservoir Simulation? Professor Brian Smart shared some ideas

As a reservoir is produced, the stresses it is under will change. While being significant, the effects of stress change can also be subtle, and it is often the extreme, obvious cases of rock mechanics working in the reservoir that confirm the importance of this subject. A well-known example is the Ekofisk field in Norway, which is expected to subside more than 6 metres as the reservoir is produced, leading to a massive engineering project to raise the platform sitting above it. This subsidence causes enormous changes in pressure in the reservoir rock.

These stress changes can affect future production processes in a number of ways. Stresses can change the permeability of fractures (or microfractures), causing them to open or close. Rock stress affects the seismic velocity of the rock, an important parameter in processing seismic data. The stress could also damage wells through shearing or crushing, the former caused by stress relief as strata of different stiffness decouple by shearing along parting planes (as in the case of Ekofisk wells)

The stress state in the ground is anisotropic, characterised by the direction of the major and minor horizontal stresses. Knowing the direction of these stresses can also be helpful when planning field development, because water flood will be much more effective if the water is flooding through the reservoir through the fractures. So you would plan the wells so a line from the injection to the production wells is in the same direction as the minor horizontal stress. .

Older fields are often produced for as long as they can leading to pore pressure depletion, and the limits to production can be due to geomechanical effects appearing rather than a lack of oil, for example new compartments appearing in the reservoir, or wells being damaged. So this adds another financial dimension to the importance of understanding and allowing for the effects of reservoir rock mechanics.

So in order to predict and manage oil production, it would be helpful to have a conceptual model for the reservoir that allows for stress changes in the reservoir, augmenting the normal flow simulators, i.e. a shared conceptual model that includes all the phenomena the various disciplines believe are important, and promotes communication between the disciplines.

Professor Brian Smart of Petromall, a former head of petroleum engineering with Heriot-Watt University in Edinburgh, presented some ideas about how to do it.

Background in mining

Professor Smart's career in natural resources began in 1964 as an apprentice in the UK coal mining industry, progressing to rock mechanics consultancy in the international coal mining industry and gold mining in South Africa (i.e. stratified (layered) deposits. He later worked on reservoir rock mechanics, beginning by applying the understanding of the rock mechanics of stratified deposits gained in the mining industry.

A big difference between mining and oil and gas is that you can observe and take measurements on the subsurface directly. There is also a different culture where people with ideas about the subsurface can talk directly to senior management and get their ideas implemented. Also, in mining, you can get a very fast indication about whether the recommendations work – if it does in fact make a tunnel or faceline more stable, or something collapses.

This is in contrast to the oil and gas industry, where measurements are often made remotely (such as from the surface), and any change, for example turning a well into an injector, will only show up in the production results in 5 years. People say, "I'll have moved on by then."

When rock is compressed

When doing his Phd, Professor Smart was looking at what happens when rock is put under compression in a test. If rock is compressed between two pieces of steel in the laboratory test, because it is softer than steel, it 'barrels' as the softer rock is restrained from expanding radially at its ends where it is in contact with the stiffer steel. Full radial expansion occurs toward the centre of the test specimen, creating a barrel shape. This barrelling can be measured using strain gauge wire wrapped around the rock.

This led to the question of what would happen in a coal mine, when you have rock layers of different softness, and you put them under changing stresses, for example by driving a tunnel through them..

Professor Smart showed that the two rock layers would actually split apart, allowing the software rock to move along a parting plane separating the two layers more than the harder one. He calls this the 'dominant parting planes' theory, because the plane (where the two rock layers touch) allows shear movement.

Coal mines use supports which can hold between 180 and 1000 tonnes, running along the side of a coal face. It is designed to present the migration of fractures in the rock above the tunnel, thus preventing it from collapsing in. The supports cost millions of dollars. So having a more accurate understanding of the strength of support required has a big impact on cost.

However, in the southern hemisphere (such as Australia), coal faces are formed in a different way, with organic matter 'washed' into place by water, rather than ending up where they grew. This means that the rock properties of the surrounding strata (the seam's "roof" and "floor" in the coal mine) are different and you have to calculate the strength of the rock support in a different way, something which the Phd work was able to help them with. Prof Smart demonstrated that by creating a simple conceptual model that not only drove the design process, but also enabled communication with decision-makers, e.g. mine management.

Furthermore, Australians already knew that the rocks encountered in coal mining were anisotropic, because they encountered extremes influencing tunnel stability (equivalent to borehole stability in oil and gas) – in some parts of Australia one of the horizontal stresses is greater than the vertical stress.

Before they started working with the ‘parting planes’ theory, engineers in Australia were having to give rock a softer value for ‘stiffness’, or Young’s Modulus, in their equations, than the rock was actually measured to have, in order to get their models to match what they saw in the subsurface.

Modelling stress

Since then Professor Smart continued with a research group at Heriot Watt, and developed rock mechanic methodologies that could be used in the oil and gas industry.

You can’t easily calculate rock stress changes in the subsurface, so they are best modelled. The research group used Visage, a reservoir geomechanics simulator developed by Schlumberger.

The stress analysis simulator works out how the changes in stresses will change the permeability (ability for liquids to flow), and the risks of damage to the wells from stresses in the rock. It will also work out how stresses (caused by changes in saturation) will change seismic velocity, for future seismic modelling.

This stress simulator can be used in parallel with a fluid flow simulator, taking the output from one as the input into another.

Making geomechanics easier

There have been a number of recent advancements making it easier to take geomechanics related measurements of the reservoir, such as from wireline logging and rock testing devices.

There have also been advances in software to make it easier to understand the structural setting of the reservoir.

All of this ought to be making geomechanics easier to do.

But the whole workflow is very complicated. This might be part of the reason that geomechanics is “not as high up the pecking order as it should be in petroleum geoscience,” he said.

Perhaps there are viable ways to make the workflow easier. For example in the use of a correlation between petrophysical logs which are run routinely and rock properties. This has been established for clastics and carbonates by Heriot-Watt. These relationships can be used to turn porosity data into synthetic rock mechanics data, he said. “This is cost saving stuff.”

Who cares about geomechanics?

Professor Smart did a quick analysis of the number of papers published on various reservoir engineering topics on the “OnePetro” technical papers database, looking over 5 x 5 year periods, from 1991 to 1995 up to 2011 to 2015.

Over the whole period check there were 12,000 publications referring to reservoir simulation and 455 on reservoir geomechanics.

However the rate of increase in reservoir geomechanics is higher (although starting from a very small base, giving a high margin of error).

A subjective reading into the numbers (and you can see for yourself on Prof Smart’s slides) could be that interest in reservoir geomechanics and wettability is growing steadily, interest in material balance is ‘kind of holding its own’ and interest in reservoir simulation ‘may have plateaued,” he said.

“I’ll take the OnePetro results as a sign of encouragement. Reservoir geomechanics is developing, I believe,” he said.

Today, there are some oil majors looking at geomechanics seriously, and at least one national oil company. There are universities looking at it, although “I see capability swinging away from UK to America (and Europe).” There are a number of service companies involved.

Some oil majors might be outsourcing their rock mechanics and geomechanics work to service companies. There’s a growing number of consultancies.

Summary

1. **Reservoir rock mechanics/geomechanics is an important topic that has input into reservoir development and management**
2. **As such it is one of several disciplines that ideally need to work together to maximise economic recovery**
3. **The collaboration between disciplines can be assisted by a conflated conceptual model of the reservoir (field) that all can relate to**
4. **The progression to decommissioning with its attendant pore pressure drawdown may provide meaningful opportunities for such collaboration**

Understanding Resevoirs and Rocks, January 23 2018, London, Attendees

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Tim Papworth, General Manager Armenia, AGAPE Armenia

Ben Seymour, Field Architect, Aker Solutions

Geoffrey Boyd, Field Development Consultant, Antium Frontfield

David Craik, Consultant, Atlaslocal

Christian Richards, Sales Manager, AustinBridgeporth

Joe M Boztas, Director/Interpreter, Boz Seismic Services

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