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The production rate variability problem with shale reservoirs: what we know and what we don't know

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Introduction

Our traditional view of shales is that they are usually seals and sometimes source rocks – but never reservoir rocks. But recent improvements in drilling and completion technologies have made production of oil and gas from shales possible. Fracture stimulation treatments can provide the missing reservoir permeability and horizontal wells allow engineers to cluster many fracture stimulation treatments in the somewhat rare shale intervals that make good oil and gas development targets. Shale exploration and development has suddenly become big business; it has added more than 100 years of natural gas supplies in North America. North American LNG import terminals are now being turned into export terminals. Nations and energy companies around the world are asking if their shales can produce oil and/or gas.

But there is an emerging issue: unexplained production variability. Urbina (2011) showed that a small percentage of the wells are producing most of the gas in the Barnett Shale, Haynesville Shale and Fayetteville Shale plays. Baihly *et al.* (2010) showed the same well-to-well productivity variations for the Barnett shale and that there is also a large productivity variation between fracture stimulation treatments within the same horizontal well bore.

Shale gas development programs using 'pattern drilling' with evenly spaced wells drilled in 'factory mode' have been very successful in lowering the development costs in this capital intensive play. Pattern drilling is based on the assumption that the reservoir is uniform in quality and productivity. But the production results quoted above show that this is not the case.

There is considerable potential value in understanding what causes this production variability and developing only the better well locations. Most North American shale gas plays are marginally economic with current gas prices. Australian shale gas plays will probably be sub-economic because our drilling costs are considerably higher than North America's. If the good well locations were predictable, then the economics of shale plays could be significantly improved. Additionally, the ability to predict the good shale well locations offers the opportunity to lower the societal impact of shale development drilling.

Many industrial and academic groups around the world are looking for the explanation(s) of shale production variability. Early in 2012 the University of Adelaide will be starting up research efforts into production variability in shale and other unconventional reservoirs: coal seam gas, tight gas and geothermal reservoirs. Those efforts will be focused on stress and natural fractures for all of the unconventional reservoirs with additional research investigating the geochemistry, stratigraphy and sedimentology of shale reservoirs.

Organisation of this article

This article is written for a general geoscience audience with little or no experience in shale reservoirs who wish to learn more about this quickly growing and very important resource. Discussed below are a number of *possible* causes of production variability in shales. Some of these ideas are rather new and not fully developed – so only time and experience will show what the truly important variables are for shale productivity. The major sections in this article discuss shale geology and geomechanics. Not covered in this article – but certainly related to production variability in shales – are the topics of completion and fracture stimulation design. This article is intended to be a brief summary of many different topics and specialists will find that some parts are sparse in detail.

Geological variability in shales

The following is a brief 'check list' of what makes a good oil or gas shale:

- *Total organic content (TOC)*: should be higher than 2%. TOC values for the 'best' shales may reach 25%.
- *Thermal maturity*: also known as vitrinite reflectance or Ro. For Ro = 0.6–0.8 kerogen will start to crack and create liquid hydrocarbons. Ro = 1.1–1.5 will generate condensate and Ro > 1.5 will generate dry gas.
- *Gas content*: determined by measuring the amount of gas that flows from a pulverised shale core sample. Can range from 40–400 scf/tonne (and higher?).
- *Thickness*: thicker shales may have more gas-in-place. Note that as a shale regionally thickens, its TOC may become lower.
- *Rock properties*: porosities of shales can range up to 15%. A low Poisson's ratio and high Young's modulus indicate that a shale has more gas, more porosity and is easier to fracture stimulate.
- *Structural integrity*: hydrocarbons can migrate out of a shale that is heavily faulted.

Variability in shales is especially confusing given the traditional view that shale is deposited in a deep-water low energy environment where the major depositional process is 'pelagic rain' of organics and clays. Little spatial variability in depositional conditions is expected with this view. But pattern-drilling results indicate a high spatial variability in production rate and recovery factor from shales. Below are some emerging ideas that could explain this variability.

Shale variability driven by sequence stratigraphy and sedimentology

We now understand that the classical thick homogeneous shales are actually comprised of stacked parasequences (Passey *et al.*, 2010). A shale parasequence may only be a metre or two thick but the organic content, porosity, and mechanical properties can change from top to bottom within a sequence. The lower part of sequences is deposited in lower energy and deeper water while the top of a sequence will be deposited closer to shorelines. This can lead to the basal portion being more organic rich with softer rock properties while the top can contain less mud and more silt (i.e. more porosity). This presents a choice when landing a horizontal well in a given sequence; going deep in the sequence may lead to better gas content, but going shallow may lead to better porosity and 'fracability'.

Shales are not just comprised of pelagic rain: spatial changes within a given shale parasequence can be driven by traditional concepts of sedimentology. Flume studies show that muds and clays can behave like coarser sedimentary particles and move along the sea floor as hyperpycnal and/or turbidity current flows (Mulder *et al.*, 2003; Mulder and Chapron, 2011). And it is not just deep water shales that make good 'shale' reservoirs; for example, the Barnett 'Shale' is actually a siltstone. Siltier shales present the risk of lower TOC, but the advantage of better porosity, fracability and deliverability. And with an increase in grain size comes higher energy depositional environments and the associated spatial variability.

As discussed above, shale properties can vary *vertically* within a sequence and certainly between different sequences. *Spatial* variations within a single shale are predicted if the concepts sedimentologists use for coarser grained sediments (turbidity currents and resultant channels and fans) are applied to shales.

High frequency variation in TOC driven by clay type

Kennedy and Wagner (2011) point out that TOC can vary rapidly vertically within a shale. They point out that these high frequency variations are related to clay types; high TOC is associated with smectite and low TOC is associated with illite. They propose that the large mineral surface area of smectite allows it to adsorb the very small organic compounds that result from the bacterial break down of organics. Illite does not have much mineral surface area and thus cannot adsorb organic compounds. These organic compounds concentrated by the smectite may be the pre-cursors to kerogen. Kennedy also proposes that the clay type variations are depositional, not diagenetic, and controlled by climate conditions and clay source provenance.

Porosity types in shales: are spatial changes expected in pore types?

Hydrocarbons can be stored in shales via adsorption, absorption and in conventional pores. Absorption occurs when methane dissolves into the water in shales. Adsorption occurs when methane is densely packed into organic particles (and smectite clays?). Absorption and adsorption will work for small hydrocarbon molecules – i.e. methane – but storage of liquid hydrocarbons in shales almost certainly requires conventional pores.

Our understanding of the different pore types in shales is evolving very quickly and is driven by new microimaging technologies such as argon-ion milling, field emission scanning electron microscopy, and micro 3D CT imaging. These technologies are showing that there can be pores in the kerogen in shales (Walls and Sinclair, 2011), although there are questions on how connected these pores are and thus what sort of permeability they can provide. Slatt and O'Brien (2011) discuss other types of porosity in shales; porous floccules, organopores, fecal pellets, fossil fragments, intraparticle grains and pores, and microchannels and microfractures. In my opinion, the most promising of these is porous floccules. Shales have a 'fabric' that is predominantly caused by stacked parallel clay platelets. Slatt's porous floccules have a different sort of fabric that occurs when shale platelets connect end-to-end to form ring structures. Their pores (centre of the ring structure) are large and can be connected to other pores – i.e. provide permeability pathways.

Important questions about these floccules are:
- How and when do they form?
- Why do they not collapse with burial?
- How common are they in the sub-surface?
- Can they provide the required permeability network to drain adjacent tighter shale fabrics?

Slatt and other authors speculate that floccules are related to turbidity flow in shales, but others speculate that floccules are built by nanobacteria. If flocculated shale porosity is present in sufficient amounts, it would be quite helpful in allowing hydrocarbons to drain from shales. And if that flocculated porosity is controlled by turbidity flows, it could lead to the observed highly variable spatial distribution of shale productivity.

Geomechanical variability: rock properties, stress and natural fractures

Local stress and fracture closure pressure

Shales require fracture stimulation before they can flow hydrocarbons (if present). One of the critical parameters in a frac job is the fracture closure pressure, which is the stress that frac fluids must overcome if they are to fracture the reservoir. Let's consider how the fracture closure pressure might change in the reservoir. The simplest expression for fracture closure pressure is[1]:

$$P_c = \frac{PR}{(1-PR)}\,\sigma_{vert} + \sigma_{h-tect}$$

where P_c = fracture closure pressure, PR = Poisson's ratio, σ_{vert} = vertical stress = integrated density log from surface to this depth, and σ_{h-tect} = local minimum horizontal tectonic stress.

Propagating frac fluids will naturally flow and break into those lithologies and/or regions where the fracture closure pressure is lower. From the above equation, we see that lithologies with lower Poisson's ratio will have a lower fracture closure pressure.

Figure 1 shows how lithology, gas saturation and Poisson's ratio vary in a vertical well with tight gas sands, gas-charged silty shales, coal and shales with little apparent gas saturation. The shale zones with both higher gas saturation (higher resistivity log) and higher porosity from silt (lower gamma log) are the target zones for shale fracture stimulation treatments. Luckily these target zones also have a lower Poisson's ratio and thus tend to take and contain a frac job. Within the red fracture stimulation target zone, siltier intervals decrease Poisson's ratio

[1]More sophisticated versions of this equation include terms that describe the effect of reservoir pore pressure, anisotropic rock properties and strain during a frac job.

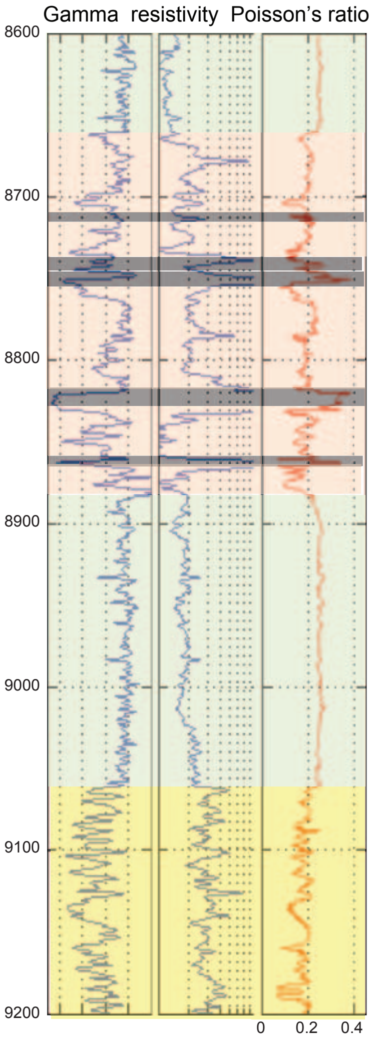

Fig. 1. *Log data for an interval containing tight gas sands (yellow), shales with little or no gas (green), coal (gray) and gassy silty shales (red). Frac jobs will tend to stay in zones with lower Poisson's ratio, i.e. yellow and red.*

while coal increases it. Silt and coal will thus change the result of a frac job (and well productivity) in ways that are difficult to model and predict. Furthermore, there is the issue of lateral changes in lithology (and Poisson's ratio) away from the well bore; if present these probably have a large impact on fracture stimulation results.

Increased quartz and carbonate can be quite helpful if it is from a *depositional* source (i.e. more porosity), but increased *diagenetic* quartz and carbonate can occlude shale porosity and hurt productivity of a frac job. Unfortunately, it is difficult to determine depositional from diagenetic quartz and carbonate from log data – and rapid lateral changes away from the well bore in this important rock property can happen in some shales (Taylor and Gawthorpe, 2003).

The above equation for fracture closure pressure includes terms for vertical and horizontal stress. The vertical stress is just the weight of the earth above the reservoir and thus will not have rapid lateral changes. However, the horizontal tectonic stress could be changing laterally, and if so, would be a major cause of production variability. Figure 2 shows one example of σ_{h-tect} varying rapidly.

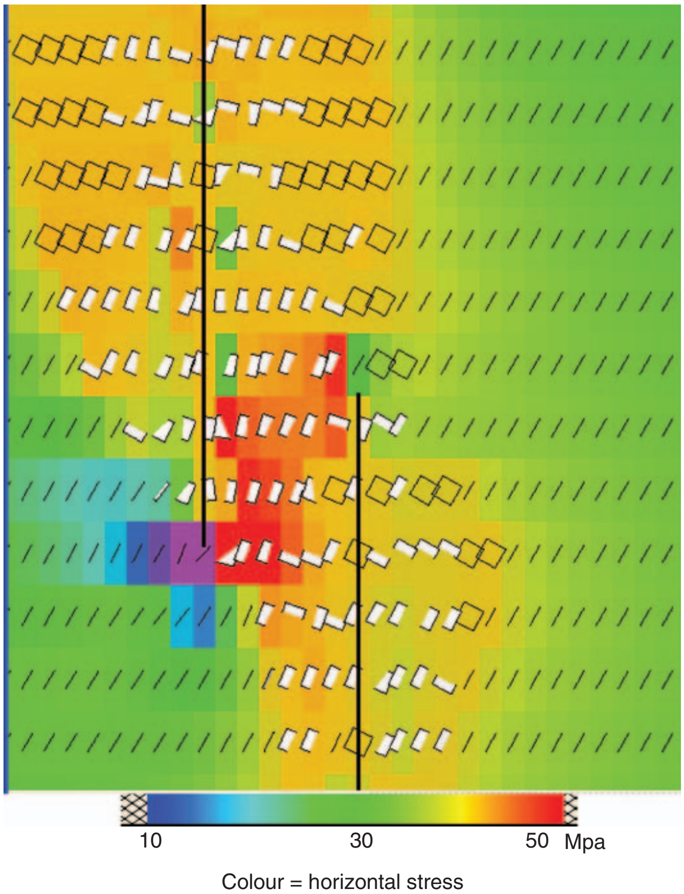

Fig. 2. *Plan view of a geomechanical model showing minimum stress (in colour) and stress orientation (lines and planes) at a fault step-over. Large black North–South lines indicate a step-over in a strike slip fault system.*

Figure 2 shows the map view of modeled[2] minimum horizontal stress in the presence of a strike-slip fault 'step-over' for shale at a depth of 2.5 km in an Australian basin. In this model, the fault has experienced strike slip movement which changes local stress – especially at the fault tips. Figure 2 models the last term in the equation above for fracture closure pressure; it averages approximately 30 MPa with swings of ±20 MPa. Compare this to how changes in lithology and Poisson's ratio impact the first term in this equation. Using frac target Poisson's ratios of 0.15 and 0.22 (see Figure 1 just beneath the coal at depth = 8750) the first term in the equation above will change between 11 and 17 MPa. This says that structure and stress can have a greater impact on fracture stimulation (and resultant production rates) than changes in lithology. Unfortunately, local stress is rarely if ever modelled in this manner as part of optimising fracture stimulation design. Instead, regional stress (obtained from sparse leak-off tests and bore-hole breakout analysis) is used as a proxy for local stress.

Shear movement on pre-existing natural fractures and microSeismic

The above model hints that pre-existing faults can have a considerable impact on local stress and thus on fracture

[2]This is a finite element model that assumes constant rock properties and constant reservoir pressure in the reservoir and allows fault strain to occur when the ratio of tangential to normal stress on a fault exceeds 0.6.

stimulation results. Das and Zoback (2011) document another mechanism by which pre-existing faults and fractures might impact a fracture stimulation treatment. This occurs when a propagating hydraulic fracture causes shear movement on a properly oriented pre-existing fault or fracture.

Das and Zoback (2011) use spectral analysis of microSeismic data recorded during frac jobs to uncover previously unnoticed low-frequency 'events'. They call these long-period long-duration (LPLD) events and attribute them to shear movement on pre-existing natural fractures, which are seen on image log data in the treated well. These LPLD microSeismic events appear to be very similar in character to traditional earthquake seismology records of large shear tectonic events. Shear movement may be quite important during a frac job as it can create fracture and fault permeability without placing frac proppant in the sheared fault[3].

While Das and Zoback (2011) hint that pre-existing fractures are helpful for fracture stimulation success, other authors point out problems associated with them. Roth (2011) shows that frac stimulation treatments can break into larger faults in the lower Barnett Shale and allow the underlying Ellenburger aquifer to kill the well with an influx of water. A different combination of fractures and stress conspire to give poor frac results in a case presented by Johnson *et al.* (2010). Fracture stimulation treatments almost always create new fractures oriented in the direction of maximum horizontal stress. Johnson attempts to use hydraulic fractures oriented by stress to connect up known pre-existing fractures and create a larger drainage area. Unfortunately in that case, the fracture is initiated in and remains constrained to a single pre-existing fracture and never connects up to other pre-existing fractures. This undesirable hydraulic fracture containment/localisation might have been prevented by ensuring that the frac treatment was not initiated in the pre-existing fracture.

How common are these pre-existing faults and fractures?

The conclusion drawn above is that pre-existing fractures and/or faults can help or hinder fracture stimulation success. And thus a key to optimising fracture stimulation treatments would be to locate wells and frac stages based on the location of faults and fractures. Faults and fractures can been seen on image logs, but these are not normally run on horizontal shale wells due to cost issues – and even if they are run, they will only see faults at the well bore. Even with an image log, it is quite possible (likely?) that an induced hydraulic fracture will grow away from the well bore and be influenced by a pre-existing fault that does not extend to the well bore.

Another method of mapping faults and fractures is to use seismic, which will never have the resolution of logs, but seismic analysis can provide information away from the well-bore and be performed pre-drill. The seismic attribute that offers the most promise for mapping small scale faults and fractures is curvature analysis (Chopra and Marfurt, 2007). My personal opinion is that assuming that subtle seismic curvature signatures are caused by faults or fractures is fraught with pitfalls. That said, Figure 3 from Backe *et al.* (2011) shows a curvature attribute from a Cooper Basin shale whose pattern is difficult to explain except by invoking a conjugate set of natural faults and/or fractures. If this pattern is caused by faults or fractures, then a pattern drilled shale development program here would have an occasional well that intersects and possibly shear stimulates a pre-existing fault/fracture (leading to a high rate well), but a majority of the wells would miss the pre-existing faults and fractures.

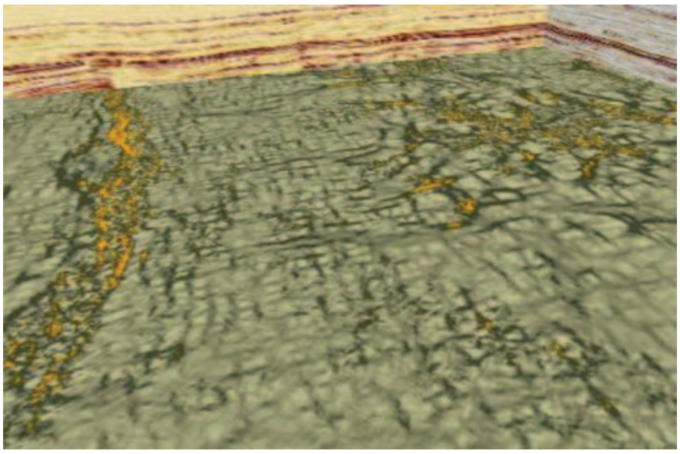

Fig. 3. *Seismic curvature attribute for a 3D seismic cube extracted on the top of a shale reservoir. The dark green cross-hatched pattern is the same pattern expected from a conjugate set of fractures.*

Fractures normally do not have the vertical offset that is required for them to be detectable on seismic. Why might the 'fractures' in Figure 3 show up on seismic data? One possible answer is that the Cooper Basin's highly differential stress regime can cause those fractures to 'pop' vertically and thus become seismically visible faults. Figure 3 is actually from a large gas field with many wells and we are currently using that well control in an attempt to validate and understand what causes this pattern.

Which pre-existing faults/fractures might be critically stressed and ready to shear?

Not all pre-existing faults and fractures can shear during a frac job; some of them are 'critically stressed' and ready to move as soon as the frac fluids start to inflate that fault and lower normal stress, but others are locked up and will be difficult or impossible to shear stimulate. Zoback (2007) predicts that faults will shear when the ratio of tangential to normal stress on that fault is approximately 0.6 or greater (this will vary with different lithologies). These normal and tangential stresses can be a complicated function of depth of burial, Poisson's ratio, reservoir pressure, local horizontal stress, frac treatment pressure and leak-off. Figure 4 shows two different numerical geomechanical models of shear displacement on a conjugate joint set. On the left model the East-West faults are 'locked-up'. The model on the right has a slightly different external stress orientation and that different orientation allows the East–West faults to shear.

Summary and conclusions

This article has briefly discussed some of the geological and geomechanical phenomena that might cause productivity variations in oil shale and gas shale reservoirs. Which phenomena are important? That will probably depend on the shale in question and will require more research and more data

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[3]This assumes that the rock properties and fault asperities are sufficient to keep the sheared fault open against the normal stress against that fault, which is another geomechanical control on shale production rates.

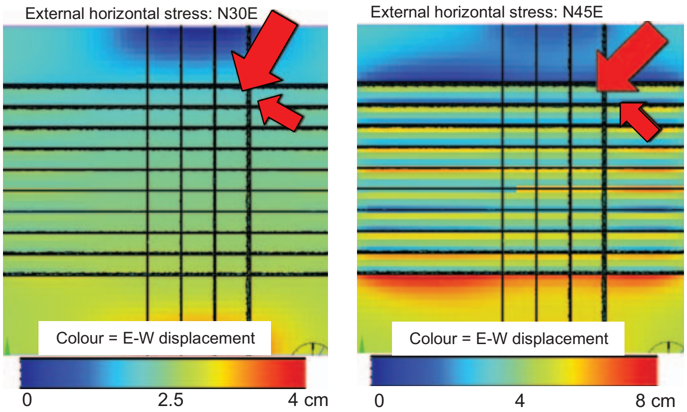

Fig. 4. *Plan view of numerical model of shear displacement on faults. Black lines are pre-existing faults. Colour = East–West shear displacement on those faults. Maximum horizontal stress for the left model is oriented N30E, and the East-West faults do not move (indicated by a lack of colour change at faults). Maximum horizontal stress for the right model is N45E and the East–West faults do move as indicated by the colour changes. Model is built for a shale reservoir in an Australian basin and assumes a frac job can raise pressure in the faults by 10 MPa. Leak-off effects are ignored.*

(i.e. expensive cores, image logs, and production logging surveys) to resolve.

A very useful way to look at productivity variations in shale reservoirs is to use the classical petroleum systems analysis approach. Petroleum systems analysis says that all of the following must be working before a conventional reservoir can contain and produce hydrocarbons: structural closure, seal, reservoir, generation of hydrocarbons in a nearby source rock, and migration of hydrocarbons from the source into the target reservoir. For shale reservoirs, similar aspects must still be working but with some important changes; migration of hydrocarbons out of the source rock must not happen (at least not to all of the hydrocarbons generated) and permeability needs to be successfully created with the fracture stimulation program. The important concept is that if just one of these fail (source, reservoir, seal etc) then the reservoir will not successfully contain and produce hydrocarbons. Applying a petroleum systems approach to shale reservoirs makes us realise that there is not a single silver bullet that can explain production variability; instead we need to use a systematic evaluation of a number of equally important criteria.

One important clue as to which phenomena are important may be contained in the spatial scale of shale production variability. Baihly et. al (2010) show that shale productivity repeatedly turns on and off in horizontal well perforations just 40 m apart. It may be easier to explain radical spatial variability with geomechanics (hydraulic fractures interacting with pre-existing faults) than with changes in TOC or porosity or rock mechanical properties. Note that a fracture stimulation treatment should grow vertically several tens of metres – or over several adjacent parasequences. This would tend to minimise the impact of geological variations. I find it easy to imagine that regularly spaced perforations and frac stimulation treatments in a horizontal well would almost randomly find and shear a critically stressed pre-existing fault – and lead to a large increase in productivity of a few lucky intervals.

In closing, I note that while Australia has a number of possible shale gas and shale oil plays under evaluation, all of them face tougher economic hurdles than comparable shales in North America due to our higher drilling and fracture stimulation costs. If Australia's shales are going to be economically produced, either our cost must be driven lower and/or we need to successfully predict and develop the highly productive well locations.

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