Next Generation Reservoir Engineering

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SUMMARY

We present a fundamental physics based understanding of the chemical, mechanical, thermal and hydrological processes and their interactions that operate over long-time scales to form and characterise the porosity/fracture networks in conventional and unconventional oil and gas reservoirs. We apply that understanding to engineer that structure for the purpose of energy extraction and resource discovery. The interdisciplinary approach links geoscience, engineering and computational science disciplines with the result of providing a step change in exploration and exploitation technologies with significant reduction in onshore gas development costs without compromising OHSE or environmental protection and assurance.

In this presentation, we will show the first results that allow incorporation of important processes in Unconventional Plays. Surprisingly, diagenetic processes such as the smectite-illite transition are found to create natural fractures under tectonic load that form the permeable reservoirs in Shale Gas/Oil Reservoirs. Results indicate that the fractures triggered by natural fluid release reaction on geological time scales are supported by a critical fluid pressure that must not be crossed to avoid sudden loss of the reservoir. Upon crossing this threshold reservoir damage can be substantial. No amount of proppant or other engineering interaction can rescue the reservoir on a human time-scale. Our novel framework allows to link the long-time scale geological processes with the design of an injection-extraction protocol to maintain critical fluid pressure. We are also able to incorporate micro-structural changes and fluid-solid interaction at grain scale. The latter has only been benchmarked for conventional carbonate plays, but the Multiscale results are encouraging for the entire spectrum of conventional and unconventional traps/source rocks. Our theoretical framework and the forward simulator is specifically designed to interface with geophysical inversion techniques for multi-scale geophysical data. Completing this data-assimilation step in the future will define Next Generation Reservoir Engineering.

Key words: Multiphysics, Multiscale, Diagenesis, Instabilities, Compaction Length.

INTRODUCTION

Exploitation of unconventional resources in shales has boomed the US economy over the last decade, while decreasing significantly its carbon footprint (Considine et al., 2010). Because of their abundance and low carbon footprint, shale gas resources have been identified as the key player in the energy landscape and the current century has been labelled the "golden age of gas" (IEA, 2011). To support these claims, the production from USA unconventional shale in the early 90's has led to an abrupt decline in conventional gas resources development. More importantly, the commercial production from shale plays in the United States has caused the CO_2 emission to be significantly reduced from almost 6000 Metric Tons (MT) a year to just over 5000 MT (Fig. 1). Therefore, unconventional shale plays indeed seem to be a way forward for securing the energy needs for any nation. In particular, Australia is well-known to host enormous unconventional oil and gas resources, and has been recently recognised as one of the emerging key exporters of natural gas resources worldwide (EIA, 2015).

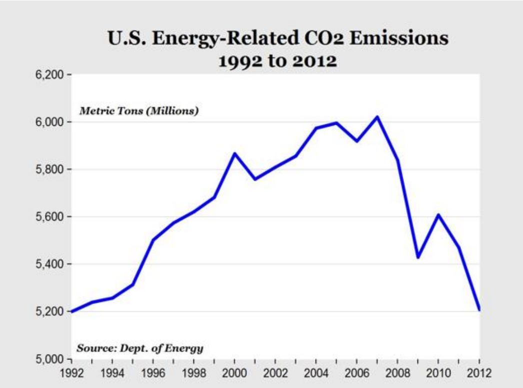


Figure 1: The CO_2 emission in the US is curbed by massive proliferation of Shale Gas use after 2006.

Despite the obvious benefits, hydrocarbon production from unconventional resources - in particular shales - has not lived up to expectations. The apparent success of exploitation of shale gas in the US revealed that their environmentally friendly CO_2 emissions are accompanied by high risk of contaminating groundwater resources and induced seismicity due to the poorly constrained stimulation techniques used (e.g. hydraulic fracturing) (Johnson and Greenstreet, 2003). The induced risks are mainly related to poor understanding of the rock behaviour at in-situ conditions and, correspondingly, the lack of advanced, custom-made and environmentally respectful exploration and stimulation protocols. The drilling risk is exponentially increasing in the case of Australia, where the shale gas resources are dominantly found at great depth, below 3 km. On top of that, Australia is in an extreme tectonic environment where – unlike the tensile case of the US - it is subjected to a highly compressional tectonic environment (Sandiford and Quigley, 2009).

The greater depth of the Australian reservoirs reduces groundwater contamination risk. However, the unconventional response of materials at these extreme conditions constitutes a formidable challenge for geomechanics and reservoir engineering. In this contribution, we aim to bridge this gap and understand the formation, geometry and fluid connectivity of high-temperature and high-pressure Shale Gas reservoirs using a multiphysics approach. By looking at the processes underpinning the formation and connectivity of oil and gas resources in these unconventional rocks we provide a better understanding of how shales respond at in-situ conditions. The application of this knowledge will allow a rigorous assessment of the future potential for the recovery of unconventional reservoirs under Australia's extreme in-situ conditions.

METHOD AND RESULTS

Unconventional energy and mineral resources define the most abundant resources available on our planet and are attractive targets for novel exploration, stimulation and production techniques. However, they are often located in a deeper and hotter impermeable environment where they are inaccessible by conventional techniques. An extreme end-member is the Shale Gas reservoir in the Cooper Basin (Australia) that is located at 3500-4000 m depth and ambient temperature conditions around 200°C. Shales of lacustrine origin (with high clay content) are diagenetically altered (J. Wust et al.).

Such diagenesis involves fluid release mineral reactions of the general type $AB_{Solid} \rightleftharpoons A_{Solid} + B_{Fluid}$ and switches on suddenly in the diagenetic window between $100 - 200$°C (Fowler and Yang, 2003). Diagenetic reactions can involve concentrations of smectite, aqueous silica compound, illite, potassium ions, aqueous silica, quartz, feldspar, kerogen, water, oil and gas amongst others. These diagenetic reactions are low temperature chemical reactions in sedimentary rocks that involve a fluid phase often associated with organic chemical/biological and physical processes that are related to the transformation. They are the equivalent of metamorphic processes at higher temperatures but switch on before greenschist metamorphism at around 300°C. The back reaction from a diagenetic fluid leads to a cementation and compaction and therefore is commonly attributed to a net porosity reduction. However, the forward reaction entails a porosity increase. That is the shale undergoes a fluid release reaction at the onset of diagenesis, a typical diagenetic reaction is:

$$2S + KFs \rightleftharpoons 2I + 4Qz(aq) + 9H_2O$$

It involves smectite *S* potassium feldspar *KFs*, illite *I*, quartz in solution *Qz(aq)* and *water* and illustrates the important role of fluid transfer in diagenesis. Such dissolution-precipitation mechanisms are thermally activated and the reaction rate is kinetically controlled (Fowler and Yang, 2003). In addition to the temperature control, the chemical reaction can, however, only proceed if a fluid phase can be transferred in tandem with a matrix that undergoes considerable compactive volume change to expel its diagenetically produced fluids. Diagenesis with dissolution-precipitation reaction therefore is an ideal showcase for THMC coupling. In classical petroleum engineering such interlayer water/gas release reactions are considered to cause cementation and significantly reduce porosity and permeability. Yet in contradiction to the expected permeability reduction Shale Gas is successfully being produced (Santos, 2013).

We propose here that the success of Shale Gas extraction from these deep reservoirs is based on THMC instabilities from volumetric compaction controlled by diagenetic reactions. We have recently discovered a new fundamental material instability (Veveakis and Regenauer-Lieb, 2015) that corresponds to dissipative (P)-waves in the diagenetic environment of creeping flow. Their high-speed solid-mechanical counterparts are well-known in impact studies. They appear as an instability in pressure through plastic volumetric shock waves (Clifton, 1983). Their analysis has been the subject of the Manhattan project and numerous studies have followed since, using plate impact studies that retrieve the equation of state upon compressive shock loading (Molinari and Ravichandran, 2004). Of special interest for the shale gas plays are the steady state solutions of the dissipative (P)-waves which are called cnoidal waves after the property of their mathematical solution as the Jacobi cn function (Abramowitz and Stegun, 1964).

They have been studied for metals (Molinari and Ravichandran, 2004) and polycrystalline solids (Eftis and Nemes, 1996). They are also recorded in soft matter at lower loading rates in spite of the dispersion of elastic waves (Petel et al., 2012). The fact that cnoidal waves can be derived as a closed form solution implies that their validity is not at question. Their relevance hence only resides in the applicability and importance to real world conditions.

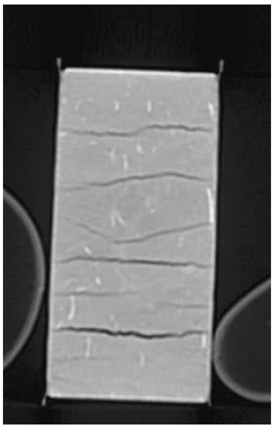


Figure 2: Horizontal bands resulting from vertical compression of a calcarenite.

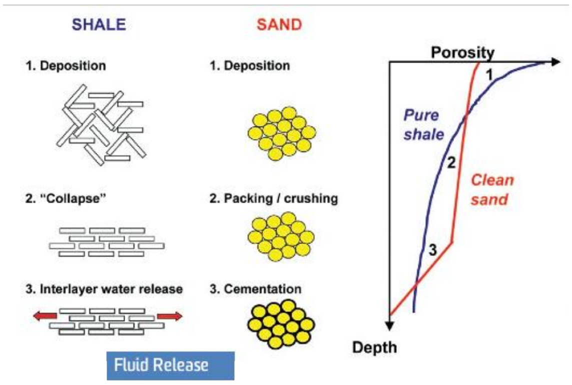
The working hypothesis to be investigated is hence, whether the success of Shale Gas extraction from reservoirs in the diagenetic window relies on the aforementioned ductile compaction and dilation bands, which act as fluid channels. Dilational and compactive fluid channels could be at a right angle or at other angles depending on the stress state and the participation of shear deformation (Regenauer-Lieb et al., 2016). The assumed ductile localisation bands are in terms of geometry similar to classical solid mechanical localisation features. Ductile dilation, shear and compaction bands can therefore easily be confused with their brittle counterparts. The main difference lies in their physical origin and their characteristic time scale. In the ductile compaction case, for example, the rate of the volumetric compaction is controlled by the diagenetic reactions. In the brittle compaction case the rate is controlled by the kinetic energy during grain crushing. Therefore, ductile instabilities are of slow (creeping flow) fluid dynamic style rather than of fast solid mechanical damage type. A diagnostic difference of ductile compaction bands is that they are forming high porosity fluid channels rather than low porosity crushed grains in the solid mechanical equivalent. The observations on the geometric appearance of cnoidal ductile instabilities is however at macroscopic level identical to the classical brittle counterpart the main difference being their slow rates of formation (Regenauer-Lieb et al., 2016). The curious feature is that they can form fluid channels in the anticrack direction, i.e. at right angles to the direction of principle compression. They can also feature tensile instabilities, and have the capability to superpose both directions without obvious interference or offsets of one over the other. Their most tell-tale signature is their periodic nature.

Figure 2 shows a laboratory experiment of a calcarenite in compression (Baxevanis et al., 2006). The calcarenite was immersed in kerosene and fully intact prior to compression. The image was visualized after compression through X-Ray tomography. The dark bands represent kerosene channels thus clearly showing the features expected from the new theory. Dark kerosene bands are oriented in the anticrack direction and exhibit periodicity. The characteristic length scale underpinning the periodicity of the kerosene channels is the compaction length L_c which can be derived from the following relationship:

$$L_c = \sqrt{\kappa \frac{\eta_S}{\eta_F}}$$

where κ is the permeability, η_S the viscosity of the matrix under a pressure load and η_F the viscosity of the fluid under the pressure load. As these quantities can be readily measured for the above shown experiments the validity of the theory can be tested in the laboratory. We are currently repeating the experiment of Baxevanis et al. (2006) with a series of samples to verify the theory in the laboratory.

While Baxenvanis et al.'s (2006) experiment aims at showing the validity of the working hypothesis for time-scales that are relevant for engineering interaction with the unconventional reservoir (thus allowing the design of a novel stimulation protocol) the more important question is to test the theory for geological time-scales as these are expected to generate the large-scale structures underpinning the reservoir. An understanding of this large-scale structure and its critical conditions is important for the exploration and reservoir engineering aspects. The fundamental question remains open whether fluid channelling instabilities exist for conditions relevant to geological time scales of formation of reservoirs will also be investigated with the help of a controlled laboratory experiment through extrapolation of creep laws obtained in creep experiments. The triaxial experimentation will be performed on samples using a small-scale high pressure-high temperature triaxial system developed at the School of Petroleum Engineering at UNSW. This small-scale high-pressure and high temperature triaxial system will be modified to conduct the triaxial testing at extreme conditions: 200°C and confining pressures up to 140 MPa. Due to the unique design of the triaxial system and the fact that it has been developed in house and the modification to higher pressure and temperatures will be straightforward. This triaxial system is in fact a small-scale cell instrumented with circumferential extensometer through four connected arms fed by high pressure-high temperature LVDTs. To elevate and maintain the temperature, an innovative setup was designed and built in which heated oil circulates within the annulus of the triaxial cell to heat-up and maintain the sample temperature which is continually monitored and recorded using installed thermo-couples. The pressure of the annulus is controlled by a back-pressure regulator on downstream outlet of the cell designed for this purpose. We will also monitor the formation of the preferential flow path e.g. if any by applying a small gas pressure on the upstream side of the triaxial cell and monitoring the pressure on the upstream and downstream sides of the sample. Our initial experimental results on sandstone samples have shown the change in shape and orientation of shear to compaction bands when moving from brittle to ductile zone (Masoumi et all 2016). These creep experiments are time consuming and will be completed over the coming three years to provide a unique data base aimed at unlocking unconventional reservoirs.



$$2S + KFs \rightleftharpoons 2I + 4Qz(aq) + 9H_2O$$

Figure 3 Three different stages of compaction of a sedimentary basin. Channelling instabilities can occur in stage 3 at a critical overburden stress.

We may test the viability of the hypothesis through following thought experiment illustrated in Figure 3, modified after (Asveth, 2003): Consider a sedimentary basin where sediments are deposited with an overall decrease in the porosity and permeability with depth. Following the initial deposition (labelled "1. Deposition" in Fig. 3) the basin will start to compact with a different material response of shale and sand. Let us assume for simplicity that for this stage (labelled "2. Collapse/Packing crushing in Fig. 3) the compacting layer is placed upon an impermeable surface. For both sand and shale compaction would start in a region next to the surface, and the diffusive movement of the fluids expelled from this region initially prevents compaction elsewhere. Fluids can only be expelled if the solid matrix compacts and the matrix can only compact if the fluids can be expelled. We end up with a hydromechanical coupling relationship that is entirely controlled by the permeability of the matrix controlling the diffusive fluid flow, and the diffusive mechanical deformation governed by the solid viscosity η_S interacting with the fluid viscosity η_F. The above described compaction length L_c describes the diffusive length over which the fluid velocity decays away from the impermeable interface with the classical diffusion profile. This situation is not conducive to instabilities as the compaction of the solid matrix is in pace with the filter pressing of the fluid. The compaction length L_c is an excellent parameter describing this stable compaction process.

Let us now assume a scenario where the sediments are buried deep enough such that temperatures exceed 100°C sufficient to cause diagenesis with porosity generation due to the fluid release reactions in the third stage (labelled "3. Interlayer water release" in Figure 3). The background permeability is already very low at this stage as most of the primary porosity has been destroyed in stage 2. A critical load during further burial may be reached where the filter pressing of the diagenetic fluids through the nanopores is no longer possible and the fluid pressure increases steadily in the pores. A final critical situation may be reached where the fluid filled pores self-organize, align and coalesce to form ductile channeling instabilities thus enabling the diagenetic reaction to continue. The compaction length L_c takes a completely different meaning in this case and defines the length scale for distance between the channeling instabilities. We would furthermore expect that in the sandier layers of the shale the porosity might still be high enough for fluid to flow and therefore these layers may act as a sink to the diagenetically released fluids. The geological observable of the cementation process from

Figure 4: Competent bands are visible in outcrops of the Eagle Ford formation. These are formed through calcite/illite/organic cementation.

the aqueous silica produced by periodic compaction instabilities would then be periodic band of soft and hard shale as observed in the Eagleford Shale shown in Figure 4(from: http://www.searchanddiscovery.com/documents/2014/51054camp/ndx_camp.pdf).

CONCLUSIONS

We have presented an approach aimed to understand the formation, geometry and fluid connectivity of unconventional high-temperature and high-pressure Shale Gas reservoirs using a recent discovery of volumetric instabilities of ductile materials. We also laid out how we intend to investigate the fundamental mechanisms, the critical parameters and the applicability of the novel theory to unconventional reservoirs. This will be achieved by testing the theory under controlled laboratory experiments, fully coupled thermo-hydro-mechanical-chemical (THMC) modelling as well as analytical modelling. The outcomes of this study will allow a rigorous assessment of the future potential of unconventional reservoirs under Australia's extreme conditions.

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