Geomechanics, stress regime and mineralogy of the Arthur Creek Formation and Thorntonia Limestone, southern Georgina Basin

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Introduction

Middle Cambrian sediments in the southern Georgina Basin contain multiple organic-rich source rocks and are prospective for both conventional and unconventional hydrocarbons. Key source rocks occur within the Thorntonia Limestone and overlying Arthur Creek Formation of the Narpa Group. The base of the Arthur Creek Formation is characterised by organic-rich 'hot' shales with TOC contents of up to 16 wt%, and petroleum explorers have targeted these for unconventional oil and gas. The development of unconventional petroleum resources is usually associated with hydraulic stimulation to improve formation permeability and enable the migration of trapped hydrocarbons to the wellbore. Successful hydraulic stimulation[3] of unconventional reservoirs is dependent on multiple factors including the geomechanical, mineralogical and petrophysical properties of the formation, and the local and regional stress regime.

Study aims and rationale

The mechanical properties of the Arthur Creek Formation and the underlying Thorntonia Limestone are poorly understood due to the limited geomechanical and stress data previously acquired in the southern Georgina Basin. In this study, we characterised the regional stress regime and the geomechanical and mineralogical properties of these formations by reviewing available wireline log data and analysing new samples collected from four wells in the southern Georgina Basin. This work complements a HyLogger™ hyperspectral logging study conducted by Geoscience Australia in the southern Georgina Basin (Ayling *et al* in review).

Mineralogy

The mineralogical composition of unconventional reservoir targets has an important control on the mechanical properties of samples. Studies have found that rocks that contain a higher proportion of ductile minerals (eg clays, chlorite and calcite) compared to brittle minerals (eg quartz, feldspar and dolomitic carbonates), behave in a more ductile fashion (Altamar and Marfurt 2014).

Thirty-four representative samples were collected from the Arthur Creek Formation and Thorntonia Limestone in the Baldwin-1, MacIntyre-1, Owen-2 and Todd-1 wells, and analysed by X-ray diffraction (XRD). Results indicate that the Arthur Creek Formation is characterised by calcite, dolomite, quartz and feldspar, and has a low clay component (<25%, **Figure 1**). Minerals grouped into the clay category include illite, muscovite, kaolinite and chlorite. The Thorntonia Limestone has a dominantly dolomitic mineralogy. These results are consistent with a petrographic assessment (**Figure 2**), and with hyperspectral logging results obtained using the HyLogger instrument (Ayling *et al* in review). Initial comparisons with mineralogical data from unconventional shale targets in North America illustrates that the prospective Georgina Basin formations generally have a lower clay component than those in North America (**Figure 1**).

Stress regime

Data from 31 petroleum and stratigraphic wells were used to derive stress parameters from which a whole-of-basin representation of the present-day stress regime was constructed (Bailey *et al* in review). Stress magnitudes were constrained using wellbore geophysical logs and tests:

- Vertical stress (σ_v) magnitudes: derived from checkshot-calibrated density logs.
- Minimum horizontal stress (σ_h) magnitudes: constrained using data from leak-off tests and formation integrity tests.
- Maximum horizontal stress (σ_H) magnitudes: constrained using established relationships between σ_h, σ_V and σ_H.

Electrical resistivity-based image logs from six wells were used in conjunction with four-arm caliper logs to assess σ_H orientations within the Georgina Basin. Common wellbore failure features, such as borehole breakouts and drilling induced tensile fractures, have been shown to be reliable indicators of stress orientations within sedimentary basins; they can be identified on both electrical resistivity-based image and caliper logs (Dart and Zoback 1989, Brudy and Zoback 1999, Hillis and Reynolds 2000).

Density logs from 13 wells within the southern Georgina Basin produce an average σ_v gradient of approximately 25 MPa/km. The mean σ_H calculated for these same wells from friction limits calculations is approximately 55 MPa/km. Through evaluation of the likely ranges of σ_h, σ_V and σ_H stresses, we interpret the southern Georgina Basin to be in a reverse to reverse/strike-slip stress regime.

Using the valid stress orientations from borehole failure data, a mean σ_H orientation of 044°N was interpreted for the study area. This is consistent with continental-scale stress trajectories of σ_H orientation as calculated for the Australian stress map (Hillis and Reynolds 2000). Further details about the methods used to derive these stress values, and the

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3 In this study we regard effective hydraulic stimulation as referring to the creation of a well-connected, pervasive fracture network in the unconventional reservoir (ie the process of fracturing). We distinguish this from the producibility of hydrocarbons from this stimulated reservoir: producibility can be affected by the nano-scale pore structure and size distribution, or physical-chemical effects (eg sorption), and these factors were not assessed in our study.

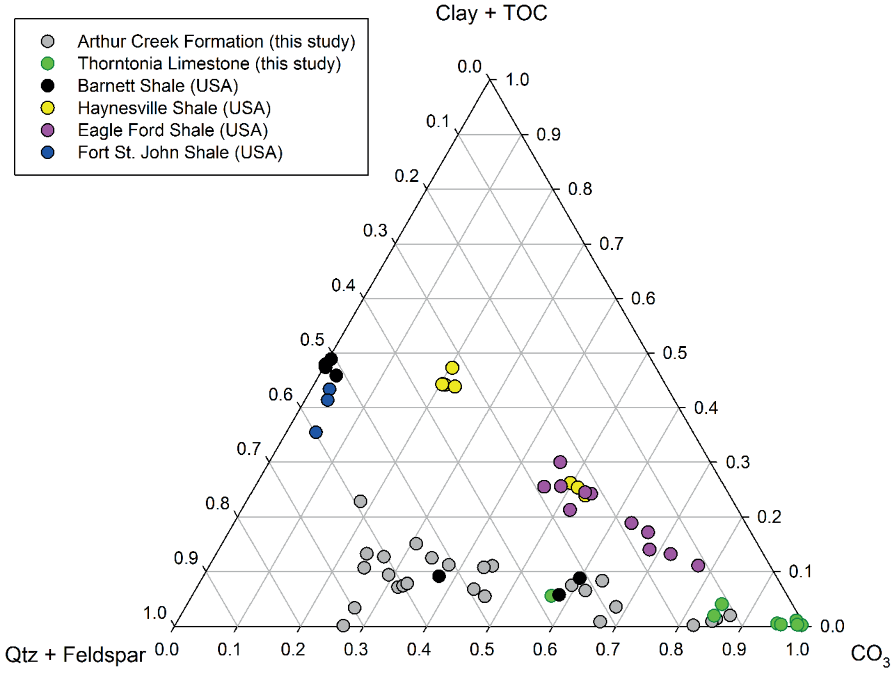

Figure 1. Ternary plot of compositional data from southern Georgina Basin, and from North American shale gas plays (data from Sone and Zoback 2013). XRD and TOC results have been converted to volume % using assumed mineral densities and a kerogen density of 1.18 g/cm³.

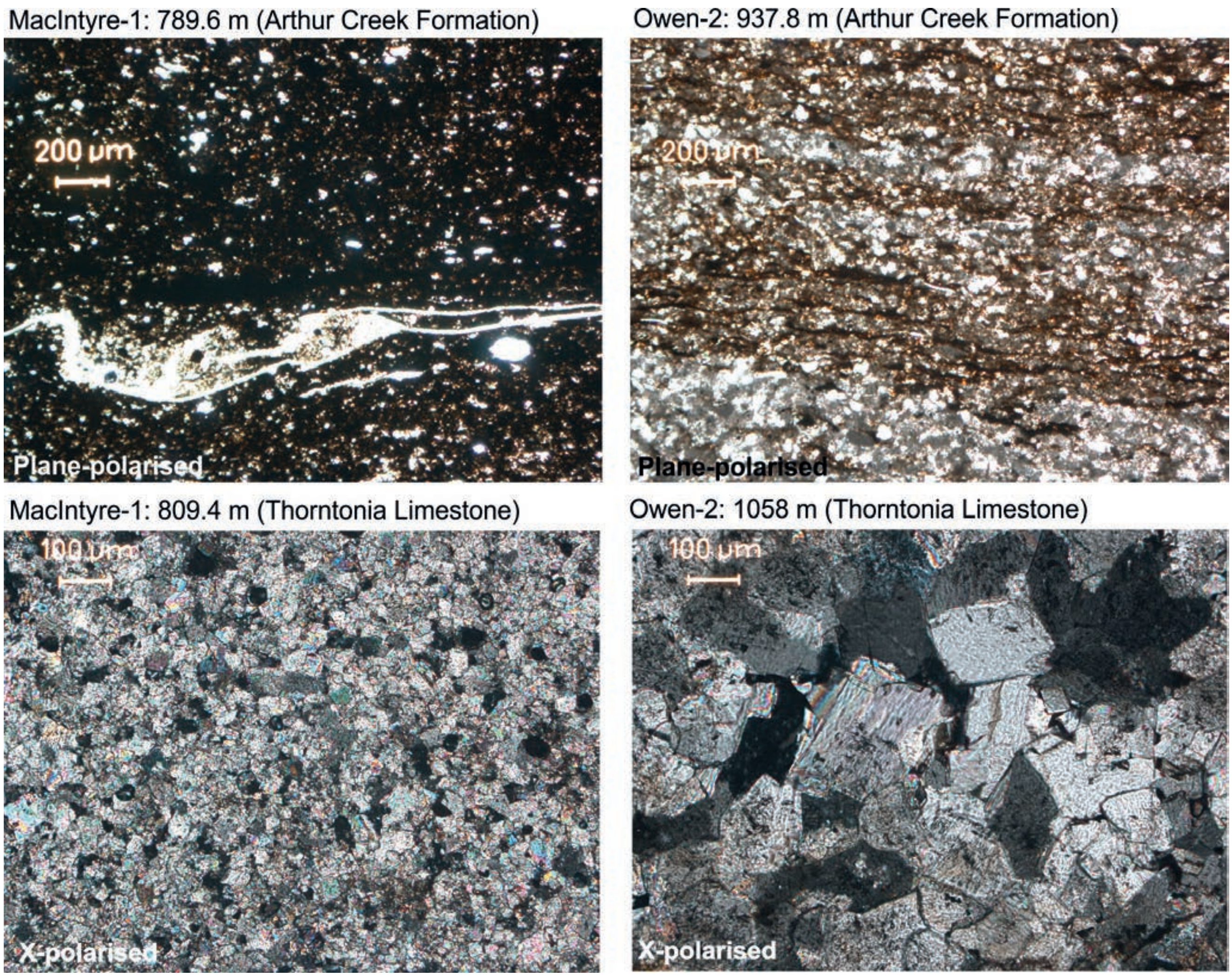

Figure 2. Photomicrographs of the Arthur Creek Formation and Thorntonia Limestone in MacIntyre-1 and Owen-2. The Thorntonia Limestone is dolomite-dominated, whereas basal sections of the Arthur Creek Formation include organic material, quartz, calcite and dolomite, and feldspars.

inherent limitations of the dataset are presented in Bailey *et al* (in review).

Petrophysical properties

Two methods were used to measure key geomechanical properties of the source rocks in the southern Georgina Basin: triaxial tests and scratch testing. Single-stage triaxial compression tests were performed on 12 samples from Baldwin-1, Owen-2 and Todd-1. The specimens were tested at confining pressures that reflected the current burial depth. From the stresses and strains measured during triaxial compression tests, the elastic properties Young's modulus (E), Poisson's ratio (σ), and compressive strength were determined for each test specimen.

In the triaxial tests, Young's moduli as measured from the loading curves ranged from 28 GPa to 97 GPa, although all but two specimens fall in the range 45–67 GPa. A specimen from the Thorntonia Limestone proved to be very stiff with a Young's modulus of 96.8 GPa. The Poisson's ratio ranges from 0.26–0.38, which is similar to the range observed in other shale gas plays in the USA, such as the Eagleford Shale and the Barnett Shale (Bodziak *et al* 2014, Altamar and Marfurt 2014). Samples from the Georgina Basin generally have a higher Young's modulus when compared to the cited samples from the USA. Studies by Britt and Schoeffler (2009) and Bodziak *et al* (2014) found that high values of Young's modulus can be favourable for hydraulic stimulation as it promotes brittle failure of the rock over plastic (ductile) behaviour.

Approximately 25 m of Georgina Basin drill core was tested for unconfined compressive strength (UCS) using the scratch technique (Richard *et al* 2012). The UCS of a rock is relevant for assessing hydraulic stimulation potential as it correlates to a specimen's tensile strength and to poro-elastic parameters such as Young's modulus. In addition, characterising the UCS can be important for ensuring that wellbore stability is maintained during drilling completions (eg Germay *et al* 2015). The scratch testing technique has an approximate spatial resolution of 1 cm thus can provide a measure of geomechanical heterogeneity along continuously scanned drill core. An example of scratch test data collected from MacIntyre-1 in the southern Georgina Basin is presented in **Figure 3**. Average UCS values for the core segments range from 65 MPa to 151 MPa. The highest UCS values are associated with the basal organic-rich shale in the Dulcie Syncline area, with average values ranging from 125–151 MPa. Intervals with the highest measured UCS are also associated with the highest UCS heterogeneity (as represented by standard deviation) and lowest friction angles (average 27°). The Thorntonia Limestone is also associated with moderately high UCS values (102–145 MPa). The basal 'hot' shale in the Toko Syncline wells is associated with lower UCS (100–115 MPa) and less heterogeneity.

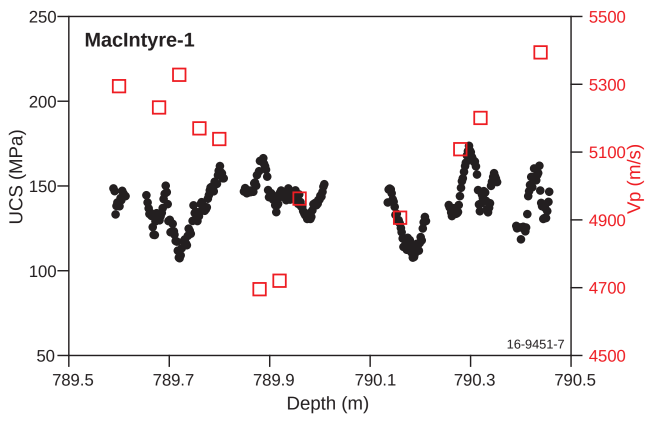

Figure 3. Scratch profile of UCS (black dots) and sonic velocity (red squares), obtained on section of drill core from MacIntyre-1 in the Arthur Creek Formation. Over tens of centimetres, large variations in UCS are measured. Gaps in UCS data are associated with breaks or cracks in core (technique requires a 1 cm buffer around cracks for best results).

Conclusion

Our study has illustrated the usefulness of acquiring geomechanical and mineralogical data to characterise an unconventional reservoir. Such data can be used alongside other datasets (eg geophysics, organic geochemistry) to inform predictions of hydrocarbon prospectivity. Future studies in onshore basins in Australia would benefit from the acquisition and public release of geomechanical data in order to provide a more robust understanding of both conventional and unconventional hydrocarbon prospectivity.

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