# fracking inquiry

**From:** Brad Scott [redacted]
**Sent:** Tuesday, 20 February 2018 7:32 AM
**To:** fracking inquiry
**Cc:** [redacted]
**Subject:** Community Update #30
**Attachments:** Yang Fei Simulation hydraulic fracturing propane Cooper Basin South Australia.pdf

**Importance:** High

Attention Justice Rachel Pepper
Dear Rachel
I am attaching a BRILLIANT paper from Yang Fei a PHD student who has communicated with Barry Goldstein and a lot of my colleagues and Principals from Canada, who have written most of the WORLD WIDE PATENTS on LPG FRACCING.
This paper gives you a very clear view, with the SAFETY and advantages of how FRACCING using Gelled LPG "NOT WATER" should be carried out for the Northern Territory and all of AUSTRALIA.

As our Prime MINISTER Malcolm Turnbull has recently stated, the MORATORIUMS and BANS on FRACCING are becoming a SOVREIGN RISK to our country AUSTRALIA

I look forward to your thoughts and comments

Regards
Brad Scott
Managing Director
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**From:** Scientific Inquiry into Hydraulic Fracturing in the NT [mailto:fracking.inquiry@nt.gov.au]
**Sent:** Wednesday, 14 February 2018 6:30 PM
**To:** [redacted]
**Subject:** Community Update #30



**14 February 2018**

## Community Update #30 – 14 February 2018

The Independent Scientific Inquiry into Hydraulic Fracturing in the Northern Territory (**the Inquiry**) is this week concluding its final round of regional community consultations on its draft Final Report.

The Inquiry has recently completed its final round of public hearings and heard from 51 groups and individuals that have put forward evidence and commentary to the Inquiry regarding its draft Final Report published on 12 December 2017.

Inquiry Chair, Justice Rachel Pepper, said the public hearings provided the community one of its final opportunities to give evidence and views to the Panel on the draft Final Report.

“At the public hearings in Darwin, Katherine, Alice Springs and Tennant Creek the Inquiry was presented with more evidence and feedback regarding our draft Final Report and the 120 recommendations within the report,” Justice Pepper said.

“In addition to public hearings, the Inquiry has also been conducting community forums where the Panel has presented its report to the community, discussed the key elements within each chapter of the report, including the recommendations, and then held round table discussions, with the community having direct access to the Inquiry’s panel members.

“The discussions and the feedback have been highly engaging and informative to both the Panel and the community.”

Justice Pepper has today confirmed all submissions to the Inquiry must be received by 25 February 2018.

“The Panel heard during the community forums that people want to know exactly when submissions must be received by the Inquiry to ensure the Panel has enough time to read, assess and consider the information being put forward,” Justice Pepper said.

“I have committed to handing the Inquiry’s Final Report to government in March 2018, therefore all submissions from the community must be received by Sunday 25 February 2018.

“Given the community demand for a deadline and the large volume of late submissions the Inquiry is continuing to receive, no further submissions will be accepted after this date to allow the Panel to read the submissions and to enable the Inquiry to complete its Final Report.

“To date, more than 1000 submissions have been received by the Inquiry since January 2017.”

The public hearings held in Darwin, Katherine, Alice Springs and Tennant Creek were live-streamed on the Inquiry’s website and all presentations to the Inquiry will be uploaded in both video and transcript format in the near future.

“There has been particular interest regarding a presentation at last week’s hearings from Lock the Gate Alliance and a response by the Inquiry and Origin Energy,” Justice Pepper said.

“I can advise this particular hearing’s transcript has been uploaded to the Inquiry’s website and is accessible through our Submission Library.

“All hearings transcripts and videos will be available on our website next week.”

The Inquiry’s community consultation program this week includes visiting the following communities:

- Tennant Creek
- Hermannsburg
- Yuendumu
- Elliott
- Jilkminggan
- Mataranka
- Ngukurr

Ends.

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# Simulation of hydraulic fracturing with propane-based fluid using a fracture propagation model coupled with multiphase flow...

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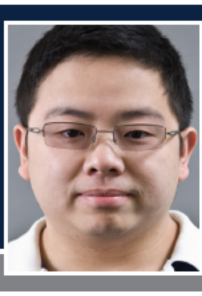
# Simulation of hydraulic fracturing with propane-based fluid using a fracture propagation model coupled with multiphase flow simulation in the Cooper Basin, South Australia



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## ABSTRACT

**In many unconventional reservoirs, gas wells do not perform to their potential when water-based fracturing fluids are used for treatments. The sub-optimal fracture productivity can be attributed to many factors such as effective fracture length loss, low load fluid recovery, flowback time, and water availability. The development of unconventional reservoirs has, therefore, prompted the industry to reconsider waterless fracturing treatments as viable alternatives to water-based fracturing fluids.**

**In this paper, a simulation approach was used by coupling a fracture propagation model with a multiphase flow model. The Toolachee Formation is a tight sand in the Cooper Basin, around 7,200 ft in depth, and has been targeted for gas production. In this study, a 3D hydraulic fracture propagation model was first developed to provide fracture dimensions and conductivity. Then, from an offset well injection fall off test, the model was tuned by using different calibration parameters such as fracture gradient and closure pressure to validate the model. Finally, fracture propagation model outputs were used as the inputs for multiphase flow reservoir simulation.**

**A large number of cases were simulated based on different fraccing fluids and the concept of permeability jail to represent several water-induced damage effects. It was found that LPG was a successful treatment, especially in a reservoir where the authors suspected the presence of permeability jails. The authors also observed that total flowback recovery approached 76% within 60 days in the case of using gelled LPG. Modelling predictions also support the need for high-quality foam, and LPG can be expected to bring long-term productivity gains in normal tight gas relative permeability behaviour.**

## KEYWORDS

Tight gas, Cooper Basin, LPG fracturing fluid.

## INTRODUCTION

Unconventional hydrocarbon reservoirs such as tight gas, shale gas and coalbed methane are becoming important resources for existing and future oil and gas supply; however, because of the low-permeable nature of unconventional reservoirs, they need hydraulic fracturing treatment. In this operation, a large volume of fracturing fluid is injected at high rates into the wellbore to overcome the rock and to induce fractures around the wellbore in the targeted formation. During a hydraulic fracture operation some of the fracturing fluid will leak-off from the fracture and invade the reservoir. In tight sand reservoirs the invaded water-based fracturing fluid may cause damage (water blockage) to reservoir permeability and fracture conductivity. Consequently, the use of water-based fracturing fluids in tight gas reservoirs may limit the potential of well productivity and result in longer flow-back times (Lestz et al, 2007).

Typically, water-based fluids are the simplest and most cost-effective solution to induce a fracture in a rock formation; however, alternatives to water-based fluids have significantly outperformed water treatments in many reservoirs. For instance, in 1970 foams were extensively used in various depleted reservoirs in which water fractures were not effective (Economides and Martin, 2007). More recently, the development of many unconventional reservoirs has prompted the industry to reconsider waterless fracturing treatments as viable alternatives to water-based fracturing fluids. In these reservoirs, the interactions between the rock formation and the fracturing fluids may be detrimental to hydrocarbon production (Ribeiro and Sharma, 2013).

The LPG fraccing technique has been commercially applied in unconventional reservoirs in North America. Gandossi (2013) reported that between 2008 and 2013, more than 2,000 LPG fracturing operations were carried out by a Canadian service company in North America. The LPG fluid's properties such as density, viscosity and surface tension with complete solubility in formation hydrocarbons are very beneficial (Gupta, 2009). In a field application, LPG is gelled before fracturing to allow transport of the proppant into the fracture (Leblanc et al, 2011).

In this paper, a diagnostics fracturing injection test (DFIT) was studied to validate instantaneous shut in pressure (ISIP), closure pressure, type of leak-off, and reservoir permeability. Then, based on mechanical rock properties from log data, minimum horizontal stress was estimated and a 3D hydraulic fracturing propagation model was developed (Pokalai et al, 2015). Eventually the results of the fracture dimension and conductivity were provided in a multiphase flow model to simulate the flowback and gas production of the fractured wells.

Since a hydraulic fracturing operation has already been carried out in well Merrimelia–62, the authors used nitrogen foam as a base case. After matching and validation with actual field flowback and history production, the new concept of permeability jail was investigated by a sensitivity analysis for three different fluid formulations: slickwater, $N_2$ foam, and LPG.

Conventional fracturing fluids include water-based and polymer-containing fluids. Unconventional fracturing fluids include non-polymer-containing fluids such as viscoelastic surfactant fluids, methanol-containing fluids, liquid $CO_2$-based fluids, and LPG-based fluids.

The ideal fracturing fluid should have:

1. compatibility with the formation to minimise formation damage;
2. sufficient viscosity to create a fracture and transport the proppant; and,
3. rapid viscosity breakdown after the proppant is placed to maximise fracture conductivity (Economides and Martin, 2007).

Figure 1 describes the significance of the fracturing fluid properties in hydraulic fracturing treatment (Economides and Martin, 2007; Economides and Nolte, 2000; Fink, 2013; Gidley et al, 1989; Valko and Economides, 1996).

The following are a few issues that need to be considered when using water-based fracturing fluids:

1. effective fracture length loss (Taylor et al, 2010);
2. low load fluid recovery (Economides and Martin, 2007);
3. flowback time (Al-Kanaan et al, 2013); and,
4. water availability.

Taylor et al (2010) suggested that the reason for phase trapping (fluid retention) is due to the high capillary threshold pressure. Values of the threshold pressure can be estimated using the Laplace-Young equation (Chalbaud et al, 2006) (Eq. 1).

$$P_C^{th} = P_{non\text{-}wetting} - P_{wetting} = \frac{2\gamma\cos\theta}{r} \quad (1)$$

In Equation 1, $P_C^{th}$ is capillary threshold pressure (psi), $\gamma$ is surface tension (dyn/cm), $\theta$ is the contact angle (degree), and $r$ is pore radius (microns).

When pressure dropdown between reservoir pressure and flowing buttonhole pressure are not large enough to overcome the capillary threshold pressure, the fluids remain in the formation (Holditch, 1979). Taylor et al (2010) reported that capillary pressures of 1,450–2,900 psig, or much higher, can be present in low-permeability formations at low-water saturation levels. In addition, Economides and Martin (2007) presented that injecting water-based fracturing fluids into high-capillarity reservoirs results in creation of high water saturation in the near-wellbore. The relative permeability of gas will be dramatically reduced by the increasing water saturation (see Fig. 2).

Furthermore, the rock formation reacts both chemically and mechanically with the injected fluid. Clays may swell when placed in contact with water, but clays do not interact significantly with $CO_2$, $N_2$ and LPG. Many unconventional rock formations lose some of their mechanical integrity when placed in contact with water. As the rock becomes softer, the rock further closes on the proppant, thereby promoting proppant embedment (Ribeiro and Sharma, 2013).

## LPG AS A FRACTURING FLUID

Hurst (1972) introduced a new stimulation technique using liquid gas. It is a fracturing treatment using an absolutely water-free fluid system. LPG gases are a mixture of petroleum natural gases (e.g. propane and butane) existing in a liquid state at ambient temperatures and moderate pressure (less than 200 psi). It behaves as other liquids do as long as they are under adequate pressure and below their critical temperature.

In field conditions, cold LPG at moderate pressure is frequently blended with proppant, gellant and breaker before being pumped into the formation for fracture. After pumping, the LPG changes phase behaviour as it converts to a gas phase due to reservoir conditions (increased pressure and temperature) and mixing with the reservoir gas (Lestz et al, 2007). Figure 3 demonstrates that with increasing the methane and propane mixture ratio, the saturation curve tends towards to the left. If the formation temperature is 160°F, with an initial 100% propane as fracturing fluid being pumped into the formation, the 100% liquid phase propane converts to a gas phase when the methane mixture ratio reaches 40%.

Leblanc et al (2011) presented a successful case for the application of a LPG-based fracturing fluid in the McCully gas field, in Canada. The results of using LPG, in comparison with a water-based fracturing fluid, show significant improvement in the McCully field, including:

1. the removal of water handling issues;
2. 100% of the propane was recovered within two weeks of the fracture treatment; and,
3. propane yielded an effective average fracture half-length that was double to that achieved by a water fracture.

In addition, laboratory tests have been conducted in the Montney Gas Reservoir in Canada, the results of which show that LPG is one of the best fracturing fluids and provides superior performance of regained methane permeability in comparison to all other conventional fluids (Taylor et al, 2010).

Gandossi (2013) demonstrated a comprehensive overview of hydraulic fracturing for shale gas production and presented a summary of the potential advantages and disadvantages of the LPG fracturing technique (see Table 1). One major disadvantage of LPG is that it is flammable and explosive; hence, it requires being carefully handled and pumped. Furthermore, nitrogen is usually mixed in either the pumping system or the fracturing fluid itself to prevent an explosion (Soni, 2014).

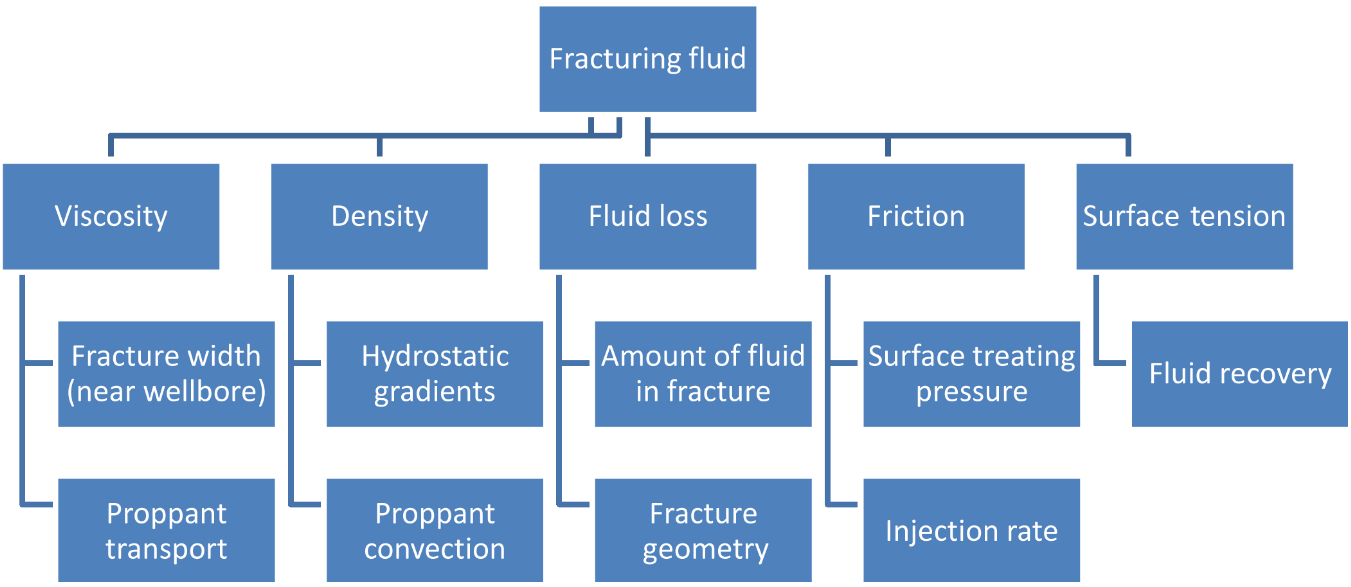


**Figure 1.** Physical and chemical properties of hydraulic fracturing fluid.

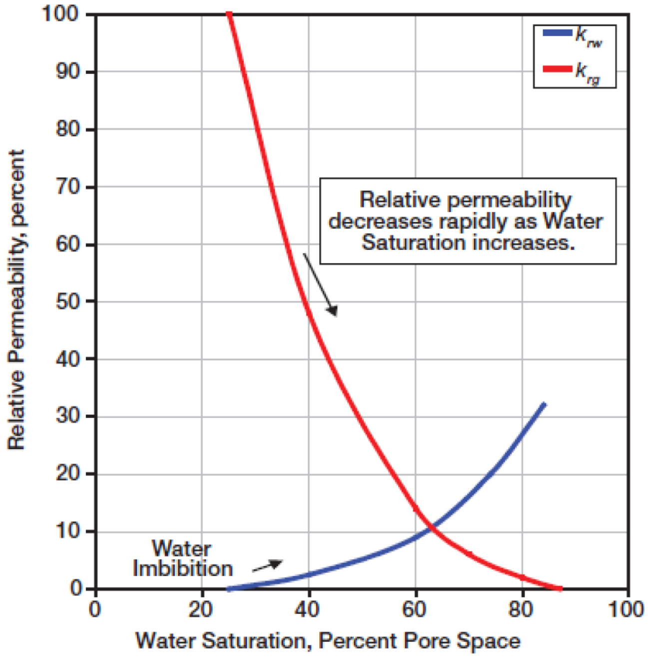


**Figure 2.** Effect of water imbibition on relative permeability change (Economides and Martin, 2007).

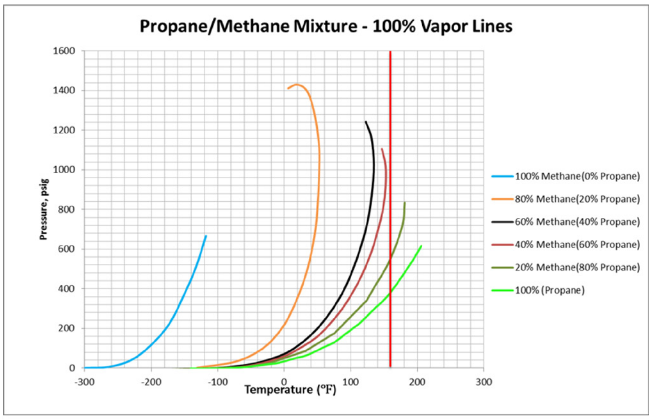


**Figure 3.** Propane-methane mixtures at formation conditions (Leblanc et al, 2011).

**Table 1.** Summary of potential advantages and disadvantages for LPG fracturing techniques (Gandossi, 2013).

| Potential advantages | Potential disadvantages |
|---|---|
| • Water usage much reduced or completely eliminated.<br>• Fewer or no chemical additives are required.<br>• Flaring is reduced.<br>• Truck traffic is reduced.<br>• LPG is an abundant by-product of the natural gas industry.<br>• Increases the productivity of the well.<br>• Lower viscosity, density and surface tension of the fluid, which results in lower energy consumption during fracturing.<br>• Full fluid compatibility with shale reservoirs (phase trapping virtually eliminated).<br>• No fluid loss, recovery rates (up to 100%) possible.<br>• Very rapid clean up. | • Involves the manipulation of large amounts of flammable propane, hence is potentially riskier than other fluids.<br>• Higher investment costs.<br>• Success relies on the formation's ability to return most of the propane back to surface to reduce the overall cost. |

## GEOLOGY AND HYDRAULIC FRACTURING IN THE COOPER BASIN

The Cooper Basin is a late Carboniferous to Middle Triassic, non-marine sedimentary basin in eastern–central Australia, spanning more than 130,000 km$^2$. The basin straddles the border of SA and Queensland, as illustrated in Figure 4. The Cooper Basin is the most significant onshore oil and gas province in Australia and is the primary onshore source for natural gas production (Gravestock and Jensen, 1998). Since the late 1960s significant volumes of oil, gas and LPG have been produced from more than 190 separate gas fields and 115 oil fields within the Cooper Basin (Santos, 2015). The primary fracture targets in the Cooper Basin tight gas are the Tirrawarra, Patchawarra and Toolachee formations. This paper's target formation is described in further detail below. The stratigraphic column of the Cooper Basin is shown in Figure 5.

The Toolachee Formation has large amounts of channels and crevasse splay deposits, with an average channel thickness of 15 ft and total gross thickness of 200–300 ft. The Toolachee Formation is widespread throughout the Cooper Basin and contains 25 of the basin's gas reserves (McGowen et al, 2007). There are two units within the Toolachee; the lower is carbonaceous shale with interbedded coal and sandstone, while the upper is sandstone with interbedded coals and shale. The reservoir permeability varies between 0.5 and 50 mD. Hydraulic fracturing in the Toolachee Formation accounts for 30% of all fracture treatments within the Cooper Basin.

Hydraulic fracturing has been used since 1968 to stimulate the Cooper Basin's oil and gas reservoirs. As of 2013, 700 wells in the Cooper Basin have been fracture stimulated and more than 1,500 individual fracture stimulation stages have been pumped (Braddeley, 2013). Figure 6 illustrates the increase in popularity of hydraulic fracturing in the Cooper Basin.

The main issues with hydraulic fracturing in the Cooper Basin have included high fracture gradients, high tortuosity and high pressure dependent leakoff (PDL) (Scott et al, 2013). Fracture gradients commonly range from 0.9–1.3 psi/ft because reservoir quality reduces or formation depth increases. High tortuosity is most likely caused by fracture tuning where the fracture remain principally vertical but is forced to counteract the maximum horizontal stress in the near wellbore region as it reorients after initiating from an unfavourable direction (Chipperfield and Britt, 2000). Lastly, McGowen et al (2007) reported that more than 65% of treatments in the Cooper Basin have observed high PDL. The typical fracturing fluids in the Cooper Basin that have been used are friction-reduced water (slickwater) and borate-crosslink gel. 100-mesh sand has been used throughout the basin to help reduce near wellbore pressure loss (NWBPL) and 20/40 to 40/70 mesh sands are the most commonly selected proppant (Pitkin et al, 2011). Special core analysis has, however, not been commonly conducted in this basin, so the relative permeability condition in most of the reservoirs remains unknown, which could potential cause low productivity and low flowback recovery by induced water-based fracturing fluid.

Merrimelia is a mature oil and gas producing field located approximately 45 km north of Moomba on the Gidgealpa-Merrimelia-Innamincka Ridge. This major positive structural feature runs the length of the SA sector of the Cooper/Eromanga Basin and separates the Patchawarra Trough from the Nappamerri Trough. Merrimelia–62 was drilled in mid-2011 as a gas development well in the Merrimelia field in SA (Fig. 7). The Toolachee was the primary target formation and the Callamurra Member was the secondary objective for Merrimelia–62. Hydrocarbon was indicated by the wireline logs. A total of 40 ft of net gas pay with a porosity of 11.6% was predicted for the Toolachee Formation. The Callamurra Member was prognosed to have 30 ft of net gas pay with a porosity of 11.9% (Santos, 2012).


**Figure 4.** Cooper Basin location (blue) and overlying Eromanga Basin (green).

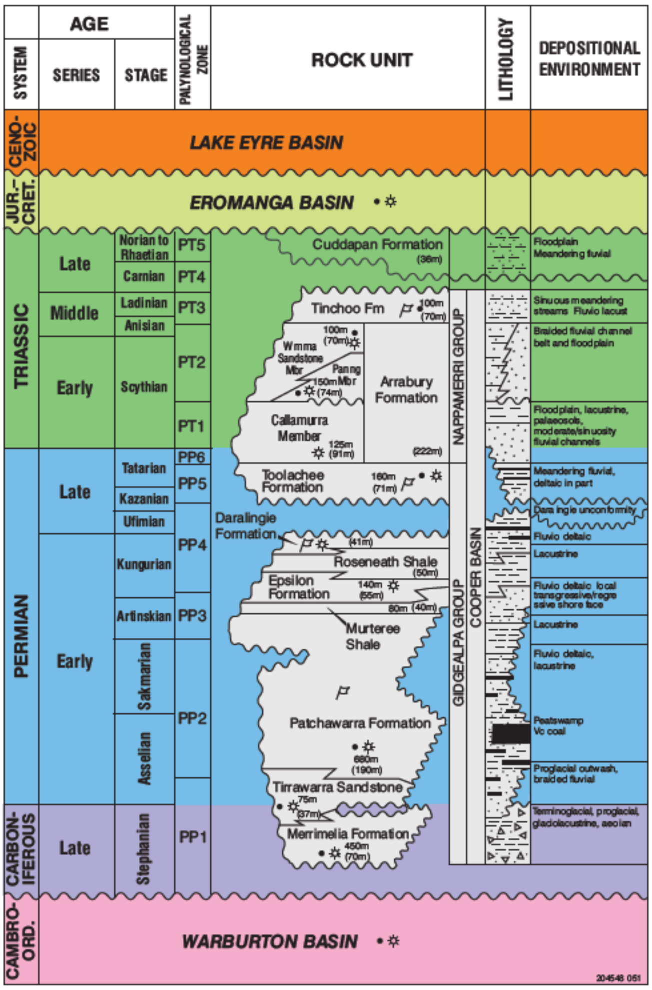


**Figure 5.** Stratigraphic summary of the Cooper Basin, SA (Alexander, 1998).

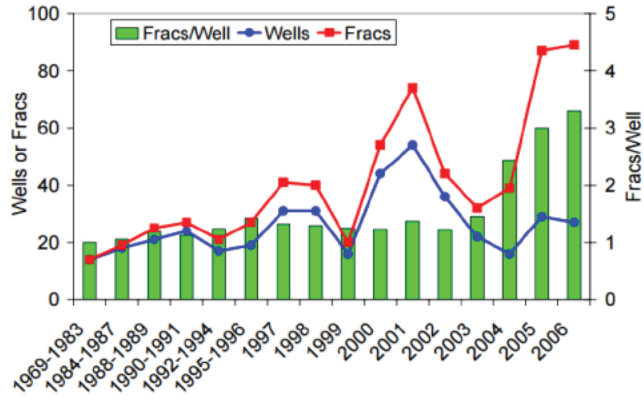


**Figure 6.** Fracture treatment in the Cooper Basin (McGowen et al, 2007).

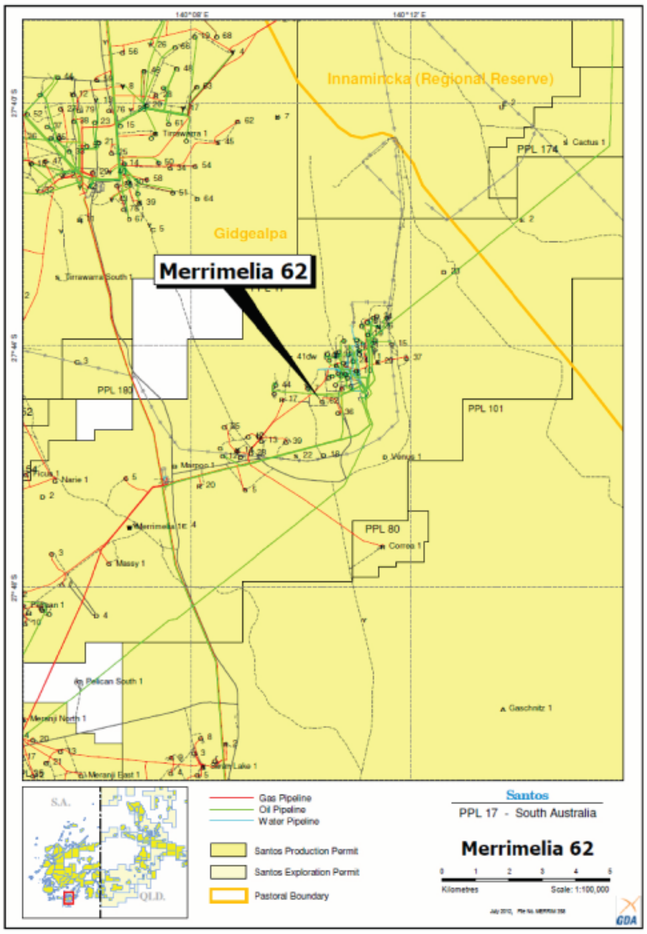


**Figure 7.** Location map of Merrimelia–62 (Santos, 2012).

## METHODOLOGY

In this paper, the authors used a fracture propagation model coupled with reservoir simulation. Figure 8 shows the details of the workflow.

First, the key reservoir properties—such as geomechanical stress and rock strength—that control the growth of hydraulic fracture needed to be determined from log data. IHS WellTest software was selected to simulate DFIT data due to its ability to model DIFT after-closure pressure without a full-scale fracture simulator. The result of pre-closure analysis are ISIP and closure pressure, which are the input parameters of the 1D mechanical earth model. Reservoir permeability and reservoir pressure are the after-closure analysis results, which are input into the fracture model. The pre-closure and after-closure results are summarised in Table 2.

Then, GOHFER (Grid-Orientated Hydraulic Fracture Extension Replicator) was used to model the fracture propagation to determine the fracture dimensions and conductivities. The actual pumping schedule for Merrimelia–62 is shown in Table 3. In this model, LPG fracturing fluid is generated from the viscosity versus time plot in the McCully field case study by Leblanc et al (2011). The temperature range is up to 150°F. As GOHFER can only generate the rheology curve based on a constant temperature, the viscosity data points on the graph are referring to this temperature. The viscosity is recorded to be 300 cP at a reference shear rate of 100 $s^{-1}$ and a base fluid in the GOHFER database is selected with similar initial viscosity.

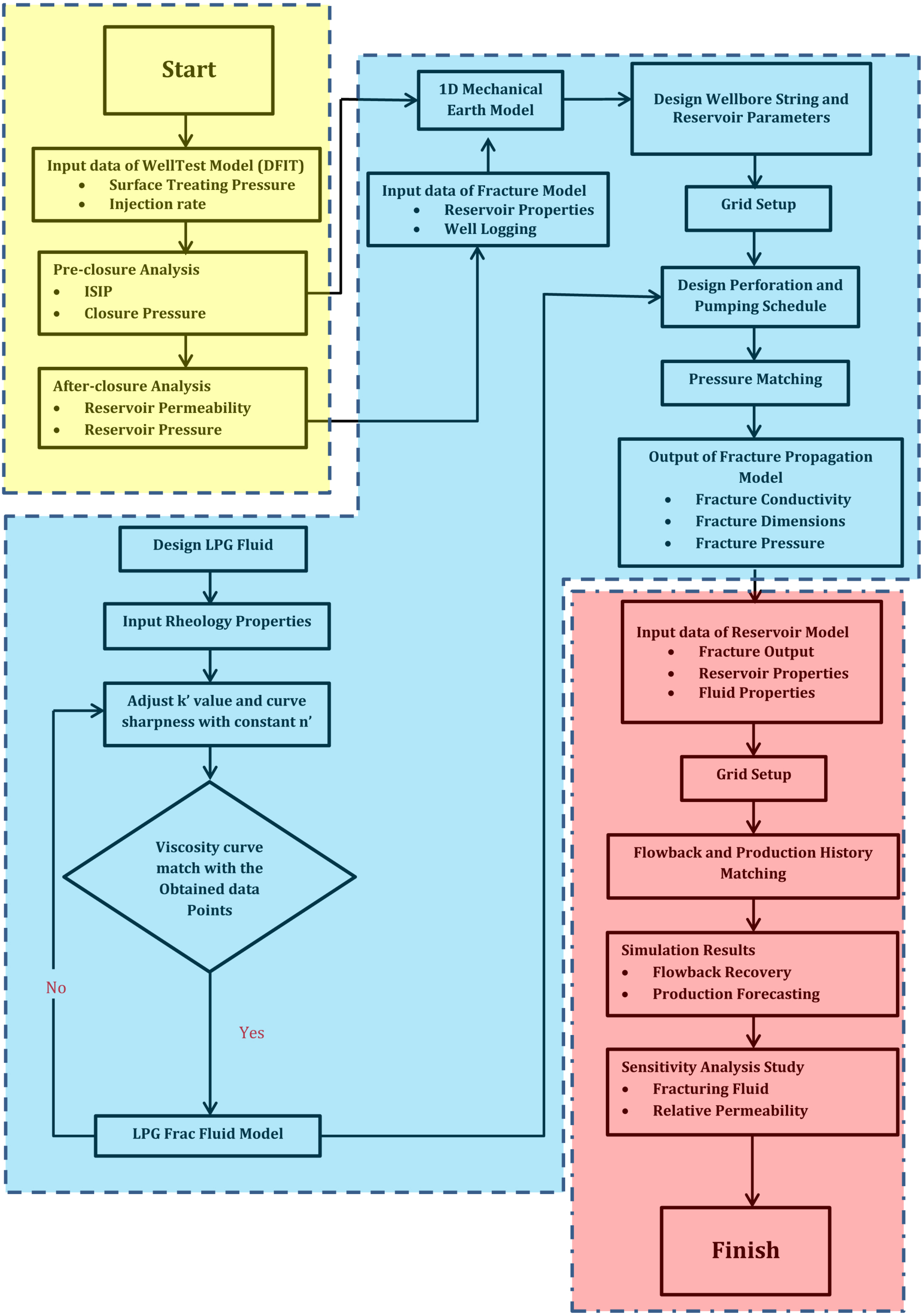


**Figure 8.** Workflow of the model development. Yellow indicates the IHS model process, blue indicates the GOHFER process, and red indicates the Eclipse process.

**Table 2.** Summary of Merrimelia–62 (stage 1) well injection fall off test results.

| | | |
|---|---|---|
| Pre-closure analysis | ISIP (psi) | 4,871.87 |
| | Closure pressure (psi) | 4,091.79 |
| | Closure gradient (psi/ft) | 0.559 |
| | Type of leak-off | Height recession |
| Nolte's after closure analysis | Permeability (mD) | 0.1 |
| | Flow capacity (mD.ft) | 0.3079 |
| | Fracture half-length (ft) | 2.28 |
| | Pore pressure (psi) | 1,869 |

**Table 3.** Actual pumping schedule for Merrimelia–62 $N_2$ treatment.

| Stage | 1 | 2 | 3 |
|---|---|---|---|
| Description | Pad | Slurry | Flush |
| Fluid type | HyborH_40 | HyborH_40 | Linear gel |
| Clean volume (gallons) | 13,064 | 11,637 | 3,542 |
| Breaker type | – | Vicon | Vicon |
| Start BH proppant concentration (ppg) | 0 | 0.5–12 | – |
| Proppant type | None | CarboProp 20/40 | – |
| BH total rate (bpm) | 26.7 | 26.7 | 26.7 |
| $N_2$ foam quality (%) | 50 | 50 | 50 |

Then the new rheology curve could be matched with the input data points by adjusting the *n'* and *k'* parameters. The simulator based on model inputs predicts the amount of proppant concentration, fracture half-length and fracture width. These key outputs (fracture conductivity, fracture dimensions and fracture pressure) are required for production modelling using Eclipse.

Finally, a reservoir simulator is used to model multiphase flow within the reservoir and the well production. In the actual field case, Merrimelia–62 has been fractured by 50% $N_2$ foam (base case). Eclipse was used to model the effect of fracture stimulation upon the productivity from Merrimelia–62. The reservoir properties of Merrimelia–62 are the main input parameters of Eclipse, as shown in Table 4. Pressure, volume, temperature (PVT) and relative permeability data was not available in the Merrimelia field so analogous data was required. Pressure, viscosity and formation volume factor data were sources from the Patchawarra Formation in the nearby Della field, while relative permeability (see Fig. 9a) and capillary pressure were provided from the Cowralli field. Flowback and history matching have been conducted to valid the model. The hydraulic fracturing results from GOHFER were used in Eclipse to model flowback recovery and production forecasting. Sensitivity analysis, which involves types of fracturing fluids and various relative permeability curves has also been studied in regards to gas productivity.

## RESULTS AND DISCUSSION

From simulation of the fracture propagation model, the surface treating pressure has been matched with the post-job report (Fig. 10). The average pumping rate is 20 bpm, which has been injected into the Toolachee Formation at a depth of 7,000 ft. The breakdown pressure indicated 6,700 psi, and propagation pressure 5,700 psi. Then, the coupled simulation was run for the base case. Figure 11 shows good matching for the true production with the model results, and the history matching parameters and results are summarised in Table 5.

**Table 4.** Reservoir properties of the Merrimelia–62 well.

| | Value | Unit |
|---|---|---|
| Measured depth | 7,325 | ft |
| Thickness | 77 | ft |
| Reservoir pressure | 1,844.8 | psi |
| Reservoir temperature | 296 | F |
| Permeability | 0.01 | mD |
| Porosity | 10.1–13.7 | % |
| Water saturation | 50 | % |
| Gas saturation | 50 | % |

Relative permeability curves are one of the major reservoir parameters controlling well productivity and, therefore, fracturing fluid selection. In some tight gas formations, water ceases to flow at a critical water saturation that is substantially greater than connate water saturation. Apart from phase trapping, the high effective stresses in the rock may impact the permeability to fluids so severely that classical theories for multiphase flow are no longer applicable (Shaoul et al, 2011). The relative permeabilities to both water and gas can be so low that neither phase has significant relative permeability across some range of saturations. This phenomenon is called permeability jail by Shanley et al (2004) . In addition, numerous authors (Cluff and Byrnes, 2010; Shanley et al, 2004; Shaoul et al, 2011) also discuss the existence of a permeability jail in tight gas reservoir rocks where the water is trapped by the high capillary pressure, thereby reducing the permeability to gas significantly. The sensitivity study will investigate this phenomenon as part of the post-fracture production analysis of tight gas reservoirs. The relative permeability curves presented in Figure 9 are in accordance with the theory described by Shanley et al (2004) and data from Cluff and Byrnes (2010). The relative gas permeability formula (Eq. 2) is (Shanley et al., 2004):

$$k_{rg} = (1 - S_w)^2 \left[1 - S_w^{\left(\frac{2+3\lambda}{\lambda}\right)}\right] \tag{2}$$

In Equation 2, $k_{rg}$ is the relative permeability of gas (fraction), $S_w$ is water saturation (percentage), and $\lambda$ is the slope (dimensionless). Figure 9 shows four examples of relative permeability curves. The first scenario (a) is the base case. The second scenario (b) is named the weak permeability jail and is based on low but finite fluid mobility in the jail saturation range. The third and fourth scenarios (c and d) are named the median and strong permeability jails, where the relative permeability curves of the fluids do not intersect and where within a region with a width of 0–0.2 (in water saturation) no fluids are mobile at all. The sensitivity of the relative permeability jail concept is analysed based on these four scenarios. In each scenario, three different types of fraccing fluids were evaluated, as shown in Table 6.

Figure 12 shows the simulation results of flowback by different fraccing fluids with original reservoir conditions. In Figure 12a, it can be seen that water production rates for both cases of 50% $N_2$ foam and LPG are about two to three times higher than slickwater. This is mainly due to the water trap-

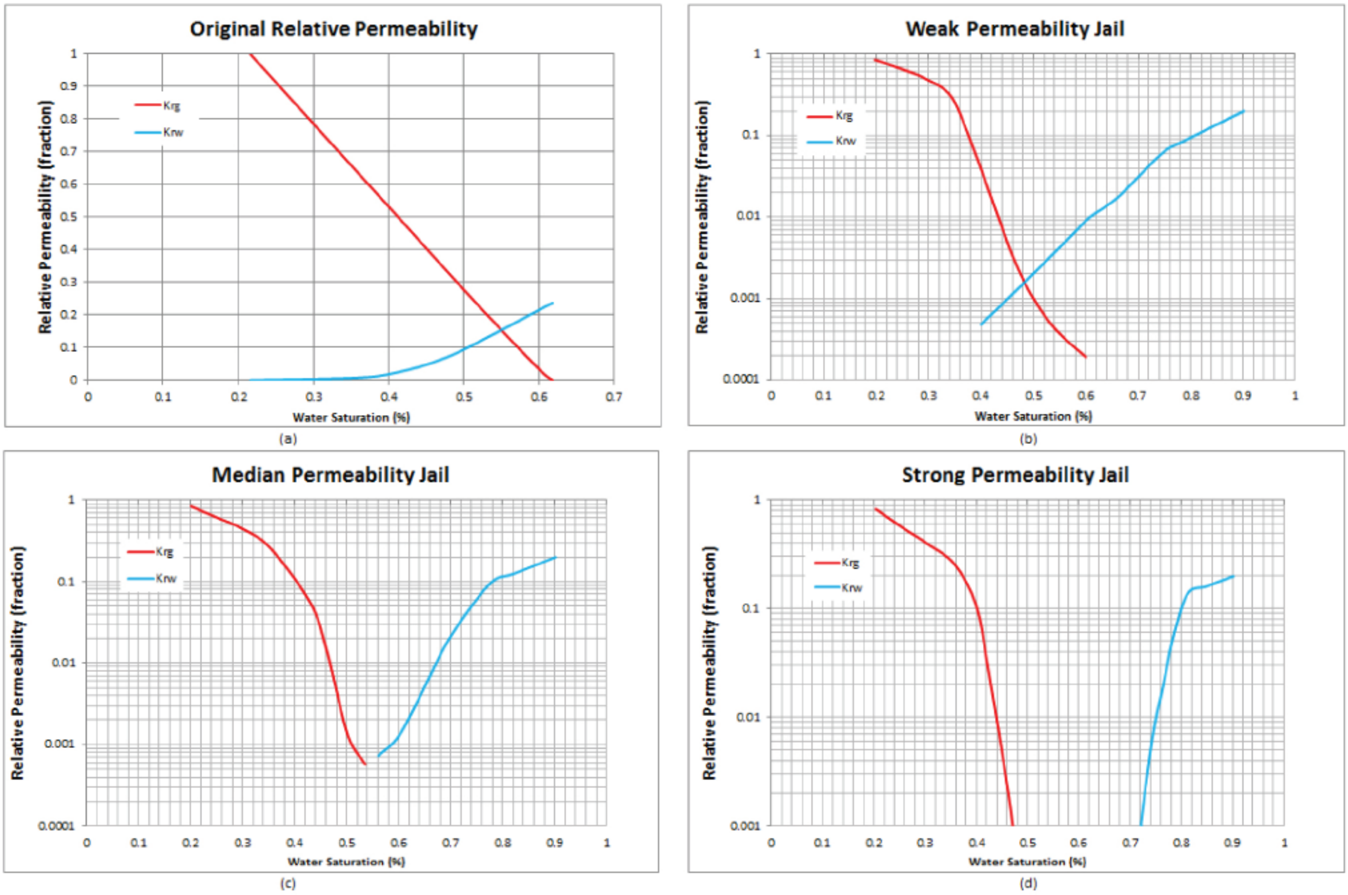


**Figure 9.** Sensitivity study of different relative permeability (rel-perm) curves. a) Original rel-perm curve for base case. b) Rel-perm curve for weak rel-perm jail. c) Rel-perm curve for median rel-perm jail. d) Rel-perm curve for strong rel-perm jail. (Shaoul et al, 2011.)

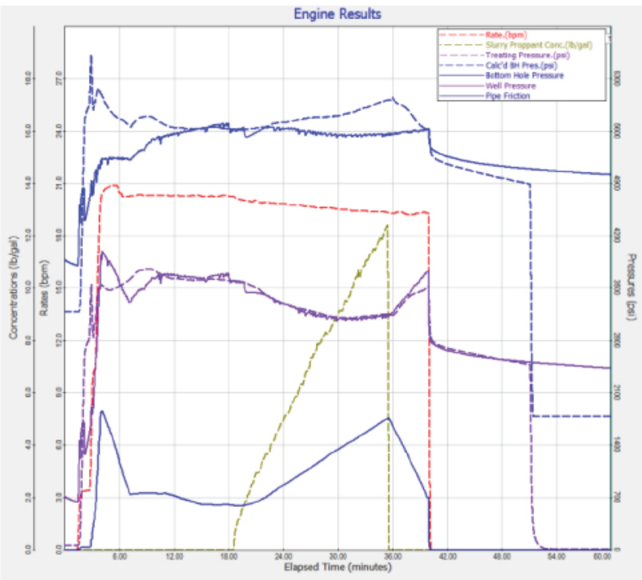


**Figure 10.** Surface treating pressure matching.

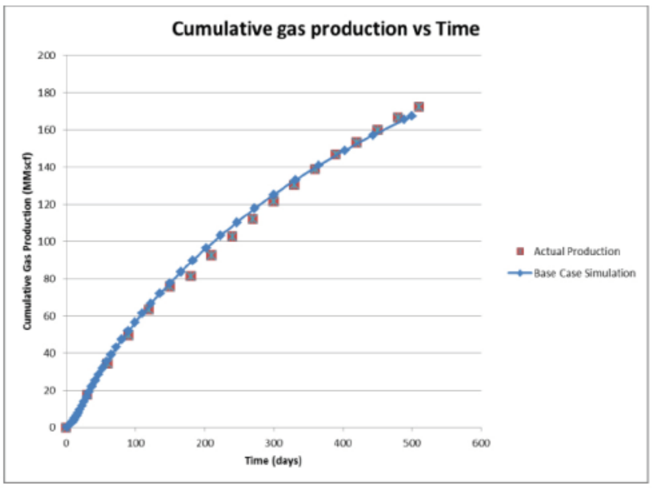


**Figure 11.** Production history matching of base case simulation.

ping phenomenon. The average conductivity of slickwater in the fraccing zone is 2,007 md-ft, whereas in the case of LPG the average conductivity is 2,598 md-ft. The lower conductivity contributed to higher capillary pressure, which would cause liquid retention at a low reservoir pressure environment. Furthermore, the stabilised fracturing pressure of LPG has 5,315 psi, whereas the fracturing pressure of the slickwater case only has 4,821 psi. This is because of the expansion mechanism from energised fluids that converts to gas in the formation, and the additional expansion energy at 500 psi would contribute to higher flowback. When comparing $N_2$ foam with LPG, LPG has a slightly better flowback rate in the initial stage (up to 50 days). This is because LPG is completely converted to the gas phase when it reaches the formation under reservoir conditions, and therefore less residual gel remains in the formation. Thus, the total flowback recovery was significantly enhanced to 76% within 60 days by using gelled LPG fracture stimulation. In addition, Figure 12b presents the cumulative water production with three fraccing fluids within 60 days. It can be seen that LPG has the highest total water production (509 STB), compared to 50% $N_2$ foam (433 STB) and slickwater (213 STB). The gas production rate as shown in Figure 13a shows that LPG reaches maximum gas production

**Table 5.** History matching results.

| | Value | Unit |
|---|---|---|
| Permeability | 1.9 | mD |
| Porosity | 0.08 | Fraction |
| Drainage area | 200 | Acre |
| Clean-up time | 50 | Days |
| Skin | 10 | Dimensionless |
| Fluid efficiency | 82.37 | % |
| Retain permeability | 68 | % |

**Table 6.** Sensitivity analysis of fluid type.

| Rel-perm/ fluid type | 50% $N_2$ foam | Slickwater | LPG |
|---|---|---|---|
| Original reservoir | Base case | Case 1 | Case 2 |
| Weak rel-perm | Case 3 | Case 4 | Case 5 |
| Median rel-perm | Case 6 | Case 7 | Case 8 |
| Strong rel-perm | Case 9 | Case 10 | Case 11 |

almost one day after the fraccing treatment, while $N_2$ foam and slickwater require 40–50 days , which also proves that LPG performs with a much faster flowback time. The total injection volume is 673 STB. The load of recoveries are 76% for LPG, 64% for 50% of $N_2$ foam, and 32% for slickwater.

Figure 13b shows cumulative gas production after a fracture treatment for three types of fraccing fluids, which are the same data as presented in Figure 13a. It can be seen that cumulative gas production will be higher if there is less water in the fraccing fluid. The cumulative gas production, however, does not differ much between $N_2$ foam and LPG. Also, if the fracture treatment uses slickwater, the cumulative gas production will decrease 50% in one year, which is about 0.8 Bscf for one well in a 200 acre spacing. Thus, proper selection of the fracturing fluid is critical to the success of the fracture treatment and long-term gas production.

The results of the sensitivity analysis are shown in Figures 14–16, and are summarised in Table 7. Figure 14 shows cumulative gas production for the weak relative permeability jail scenario. It can seen that cumulative gas production of LPG presents higher gas production (137 MMscf), followed by $N_2$ foam (110 MMscf) and slickwater (51 MMscf) at 230 days. In the median relative permeability jail scenario, Figure 15 shows the cumulative gas production of LPG (107 MMscf) remains the highest gas production, followed by $N_2$ foam (79 MMscf) and slickwater (51 MMscf). Similarly, with the weak and median cases, the strong case in Figure 16 also shows that LPG performs better than other fraccing fluids.

Figure 17 shows the results of reservoir simulation of cumulative gas production with different fraccing fluids at various reservoir scenarios. Case 2 (LPG, original rel-perm) pro-

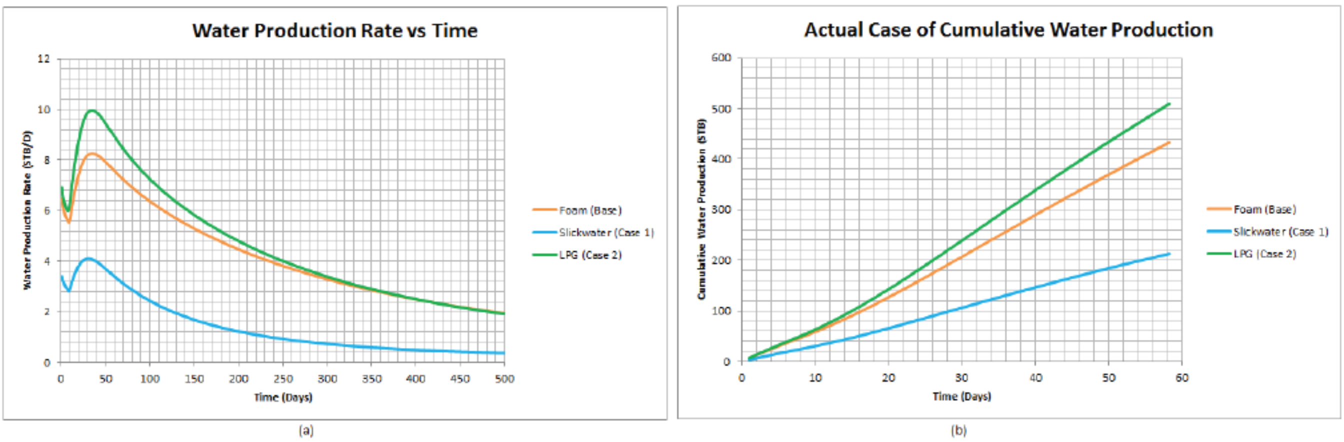


**Figure 12.** Effect of different fluid types on original reservoir condition. a) Water production rate versus time. b) Cumulative water production versus time.

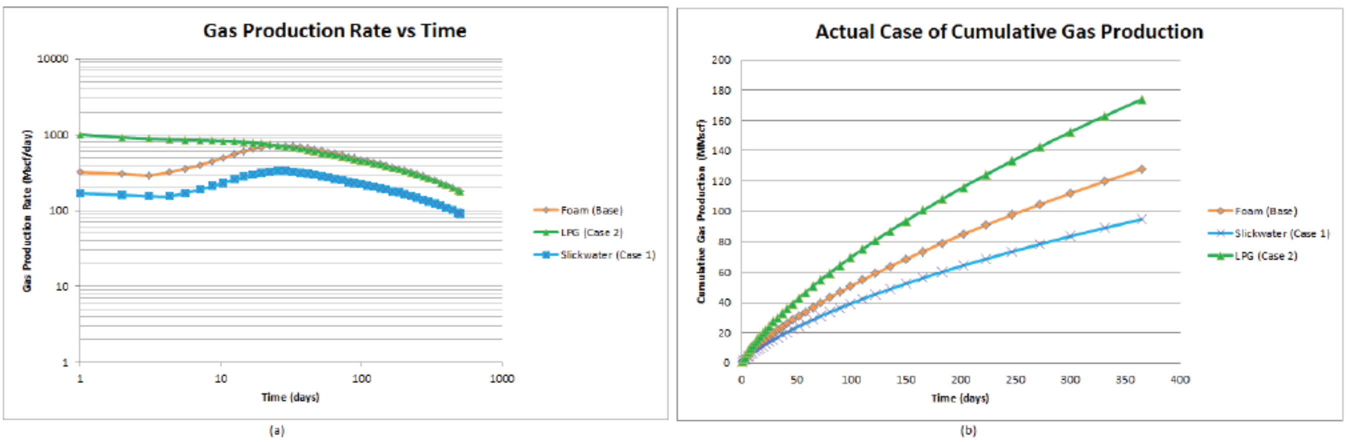


**Figure 13.** Effect of different fluid types on original reservoir condition. a) Gas production rate versus time. b) Cumulative gas production versus time.

vides the highest gas production of 170.9 MMscf compared to the base case (50% of $N_2$ foam, original rel-perm) and case 1 (slickwater, original rel-perm). The authors found that with more severe liquid sensitive formations (from original to strong rel-perm), the cumulative gas production of all the fraccing fluid would decrease to 47%. Comparing between case 2 and case 1, if no water trapping was assumed in LPG (case 2), slickwater (case 1) could cause 53% of water blocking in the original rel-perm formation. This is also true at other reservoir scenarios when comparing with slickwater, which consequently induce 53% effective fracture half-length loss. The authors also found that when comparing with 50% $N_2$ foam, the results of LPG show that in the case of normal relative permeability behaviour, there is no significant benefit on the post-fraccing production. In the case of the weak relative permeability jail, however, there is a benefit to be gained in the early-time production during the clean-up period that lasts several months.

## CONCLUSIONS

LPG fracturing has the potential to eliminate all issues associated with water use and disposal, which is a key challenge in conventional hydraulic fracturing. Also, there are many advantages in using liquefied petroleum gases for hydraulic fracturing if it can be done safely. This paper introduced a fracture propagation model coupled with a multiphase flow model for an unconventional reservoir in the Cooper Basin by using actual field data. The simulation demonstrated the effectiveness of liquid retention and gas productivity enhancement under a low-pressure, high-temperature environment. The permeability jail has a negative impact on gas production. In a highly liquid sensitive formation (from original to strong rel-perm), the cumulative gas production of all the fraccing fluids would decrease to 47%.

In the model, the resulting water production rates of foam and LPG are about two to three times higher than slickwater due to additional fracturing pressure. When comparing $N_2$ foam to LPG, LPG has slightly better flowback rates in the initial stage (up to 50 days). Thus, the total flowback recovery was significantly enhanced to 76% within 60 days by using gelled LPG fracture stimulation. In a normal tight relative permeability case, the results show that there is a potential of getting up to 53% of effective fracture half-length loss by slickwater. When looking at the possibility of removing the water phase completely (gelled LPG fraccing), there is a potential of obtaining up to 53% of incremental gain comparing with slickwater in all the cases. In the case of 50% $N_2$ foam, however, the results show that there is no significant benefit on the post-fraccing production under this permeability behaviour. Thus, higher quality foam is recommended in a low pressure water sensitivity formation. The permeability jail concept needs to be explored further with core testing in the Cooper Basin. Laboratory experiments are necessary to verify the presence of a permeability jail in low permeability sandstones. Moreover, to further validate the fracturing model, rheology experimental laboratory tests are recommended.

## NOMENCLATURE

| | |
|---|---|
| $k$ | Formation permeability (mD) |
| $k_{rg}$ | Relative permeability of gas (dimensionless) |
| $\mu$ | Viscosity (cP) |
| $P_c^{th}$ | Capillary threshold pressure (psi) |
| $r$ | Pore radius (microns) |
| $\theta$ | Contact angle (degree) |
| $S_w$ | Water saturation (percentage) |

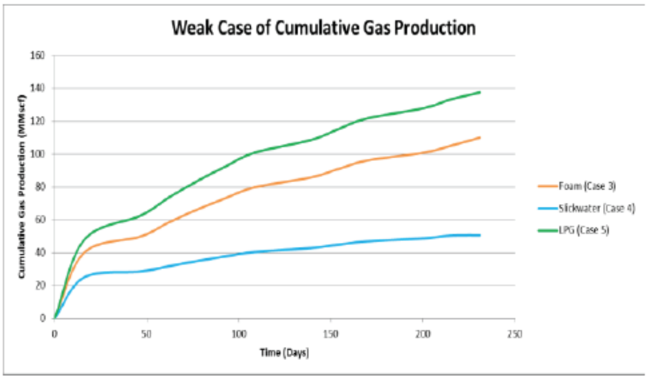


**Figure 14.** Effect of different fluid types on gas production (weak case).

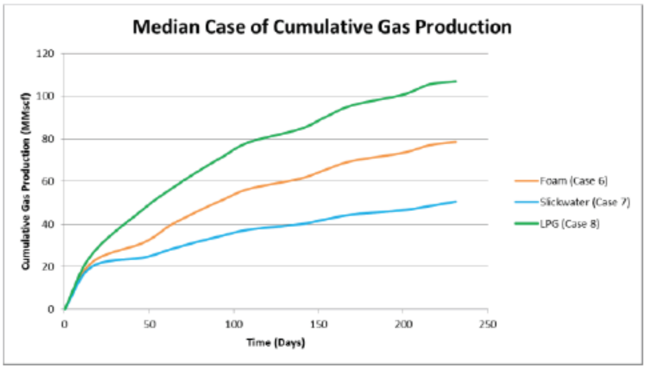


**Figure 15.** Effect of different fluid types on gas production (median case).

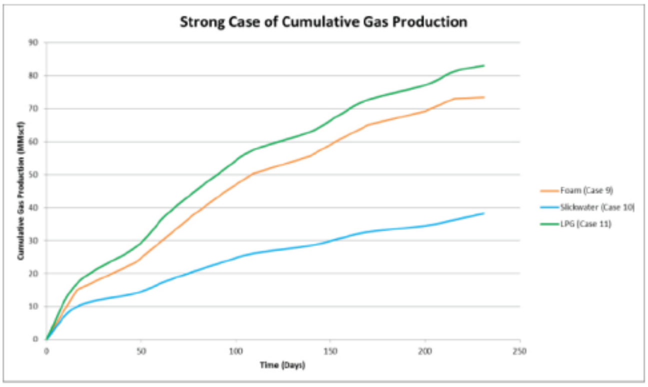


**Figure 16.** Effect of different fluid types on gas production (strong case).

**Table 7.** Results of sensitivity analysis.

| Properties | Fraccing fluid type | Rel-perm type | Gas cumulative at 230 days (MMscf) |
|---|---|---|---|
| Base case | $N_2$ foam | Original reservoir | 167.5 |
| Case 1 | Slickwater | Original reservoir | 80.7 |
| Case 2 | LPG | Original reservoir | 170.9 |
| Case 3 | $N_2$ foam | Weak perm jail | 110.2 |
| Case 4 | Slickwater | Weak perm jail | 50.7 |
| Case 5 | LPG | Weak perm jail | 137.7 |
| Case 6 | $N_2$ foam | Median perm jail | 78.5 |
| Case 7 | Slickwater | Median perm jail | 50.6 |
| Case 8 | LPG | Median perm jail | 106.9 |
| Case 9 | $N_2$ foam | Strong perm jail | 73.5 |
| Case 10 | Slickwater | Strong perm jail | 38.2 |
| Case 11 | LPG | Strong perm jail | 83.2 |

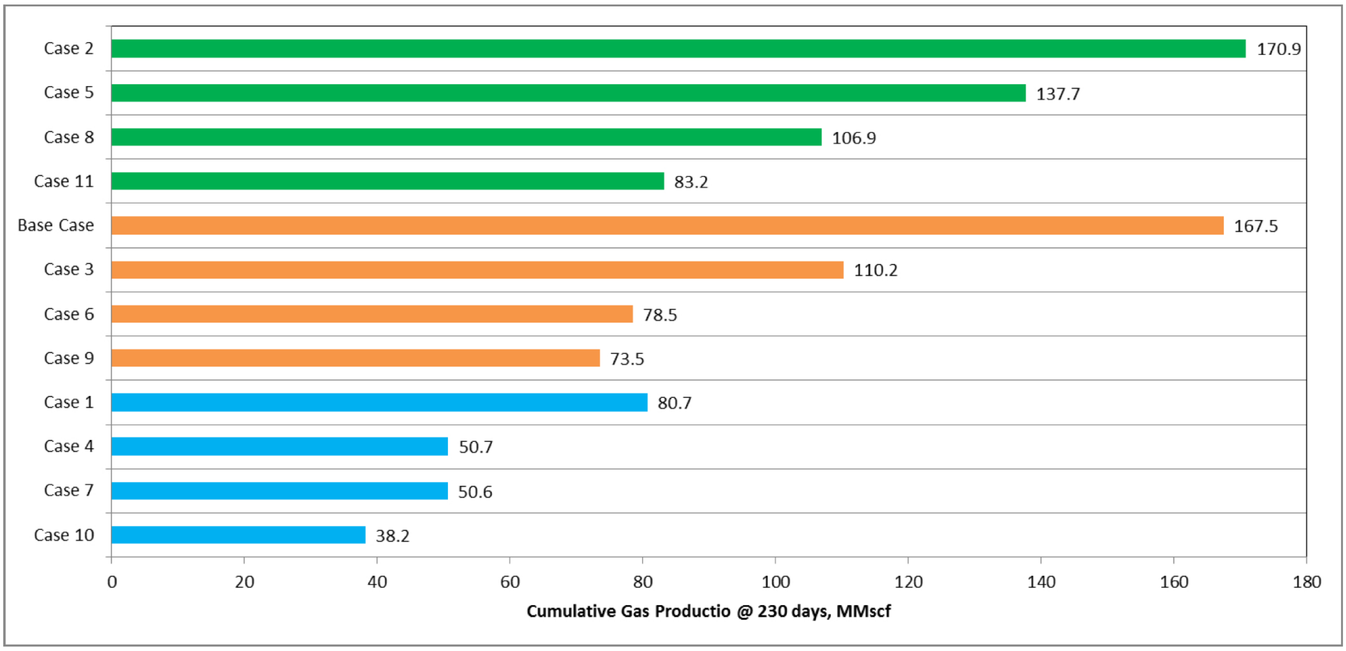


**Figure 17.** Cumulative production for reservoir simulation with various scenarios. The green colour represents LPG fluid, orange represents 50% $N_2$ foam, and blue represents slickwater.

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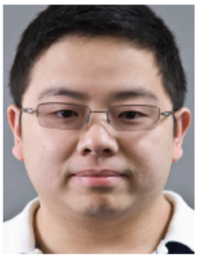

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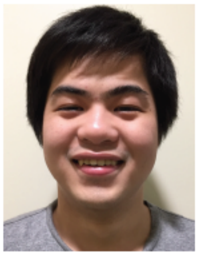

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