Integrating petrophysical, diagnostic fracture injection test (DFIT) analyses, hydraulic fracture, and reservoir modelling to design, evaluate and improve stimulation effectiveness in low-permeability coals

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Introduction

In recent years, unconventional resources such as coal seam gas (i.e., coal bed methane or CSG), shale gas reservoirs, and tight gas have been important in meeting escalating worldwide energy demands with conventional resource depletion. Of these, CSG represents the largest proven unconventional resource in Australia and has provided a reliable feedstock for Liquefied Natural Gas (LNG) export from Eastern Australia. Many Australian CSG Contingent Resource areas demonstrate low interconnected porosity with low-permeability values, resulting in low productivity indices (PI), and require more effective extractive technologies to achieve economic rates.

Hydraulic fracturing has been the primary stimulation method for low-permeability CSG reservoirs. Alternatively, horizontal wells have become commonplace and can improve the effectiveness of coal seam gas reservoir drainage from single seams. During well stimulation, high-pressure fluid leak off into CSG reservoirs increases as a result of pressure-dependent leak off (PDL) at lowered net effective stress (NES). This leak off activates pre-existing natural fractures and enhances interconnectivity between the induced fractures, natural fractures, and the small-scale cleat fabric. Unfortunately, these fracture networks may be subject to closure as the post-hydraulic fracturing pressure declines and NES increases, thereby reducing the enhanced permeability region [i.e., the stimulated reservoir volume (SRV)] and resulting productivity index (PI)]. The application of graded particle injection (GPI) or micro-proppants in stress-sensitive reservoirs has been proposed to maintain these enhanced conductive flow paths and expand the SRV along the fracture length and propped fractured height. Thus, reservoir deliverability rates and an estimated ultimate recovery (EUR) can be increased by micro-proppants maintaining this SRV and reducing detrimental pressure-dependent permeability (PDP) effects.

This study presents a workflow to evaluate the effectiveness and economic benefits achievable by micro-proppant application coupled with horizontal well, multi-stage hydraulic fracturing in CSG reservoirs. We demonstrate this process using a multidisciplined approach incorporating petrophysical and diagnostic fracture injection test (DFIT) data into hydraulic fracture designs and reservoir models to produce economic analyses, using case study data from published Upper Baralaba Coal Measures in the Bowen Basin (Johnson et al., 2002, Burgoyne et al., 2015). This study complements prior studies (i.e., radial, single bi-wing fractures) and provides guidance on the co-application of horizontal, multi-stage hydraulic fracturing and micro-proppants. For completeness, a range of factors will be examined in this model including initial permeability/porosity, permeability anisotropy, lateral length, number of fractures, fracture half-length, and conductivity of the SRV around the fractures.

Method

A newly integrated workflow (Figure 1) was developed to investigate the benefits of co-application of micro-proppants with horizontal well, multi-stage, hydraulic fracturing to improve CSG well performance and increase well EURs.

- **Hydraulic fracture modelling**

Petrophysical log data (i.e., gamma-ray, density, and sonic logs) were used to construct a 1D stress profile, which was calibrated based on case DFIT data published by (Johnson et al., 2002). After calibration, the stress profile was used along with a planar 3D fracture simulator (GOHFER) (Barree 1983) to develop hydraulic fracture dimensions and evaluate the SRV achievable by micro-proppant injection. Three different scenarios with varying permeability (i.e., 0.1, 1.0, and 10 mD) and dependent estimated porosity (i.e., 0.5, 1 and 2%), used similar fluid and proppant staging and constant PDL and transverse storage coefficients (i.e., 0.005 psi^{-1}) as reported by Johnson et al. (2002). An optimum packing of the fracture system based on selective particle jamming was assumed. The injection schedule was varied to achieve a consistent proppant concentration of 1.5 lb/ft^2 over differing fracture half-lengths. The enhanced SRV regions (see Figure 2) were based on the modelled leak off volume, assuming that unpropped region would be available for micro-proppant placement.

- **Reservoir modelling**

Fracture properties (i.e., fracture half-length, fracture conductivity, SRV area) are defined from the hydraulic fracture modelling and used to construct a 2D cartesian reservoir model representing a bi-wing fractured well as shown in Figure 3, using a pressure-dependent reservoir simulator (GEM 2020). The model includes permeability anisotropy [i.e. 2:1 or parallel: orthogonal to the hydraulic fracture (k_x, k_y)] and an enhanced region of permeability around each fracture. Three different hydraulic fracture scenarios, with varying half-lengths based on frac modelling, were evaluated for each permeability case. A dual porosity system and Palmer and Mansoori (1998) pressure-dependent permeability model were incorporated and input values were history-matched to observed well (Scotia 5) permeability and productivity index responses reported by Burgoyne et al. (2015), varying cleat compressibility and volumetric strain at infinite pressure. The resulting EURs from applying 5, 10, 15 or 20 fracture stages which generate lateral lengths from 250 to 1000m respectively were analysed. Table 1 summarizes the input and history-matching parameters.

- **Economic analyses**

Finally, economic evaluations were made of the several reservoir modelling scenarios to determine the economic feasibility of micro-proppant co-application with horizontal, multi-stage hydraulically fracturing in CSG reservoirs as well as attempt to estimate the optimal number of fracture stages. The resulting EURs from the varying scenarios were used along with estimates of Australian CSG gas prices, well costs (CAPEX), Queensland royalties and taxes along with estimated operating costs (OPEX) over 15 years to derive net present value (NPV) results for each scenario and permeability/porosity combination.

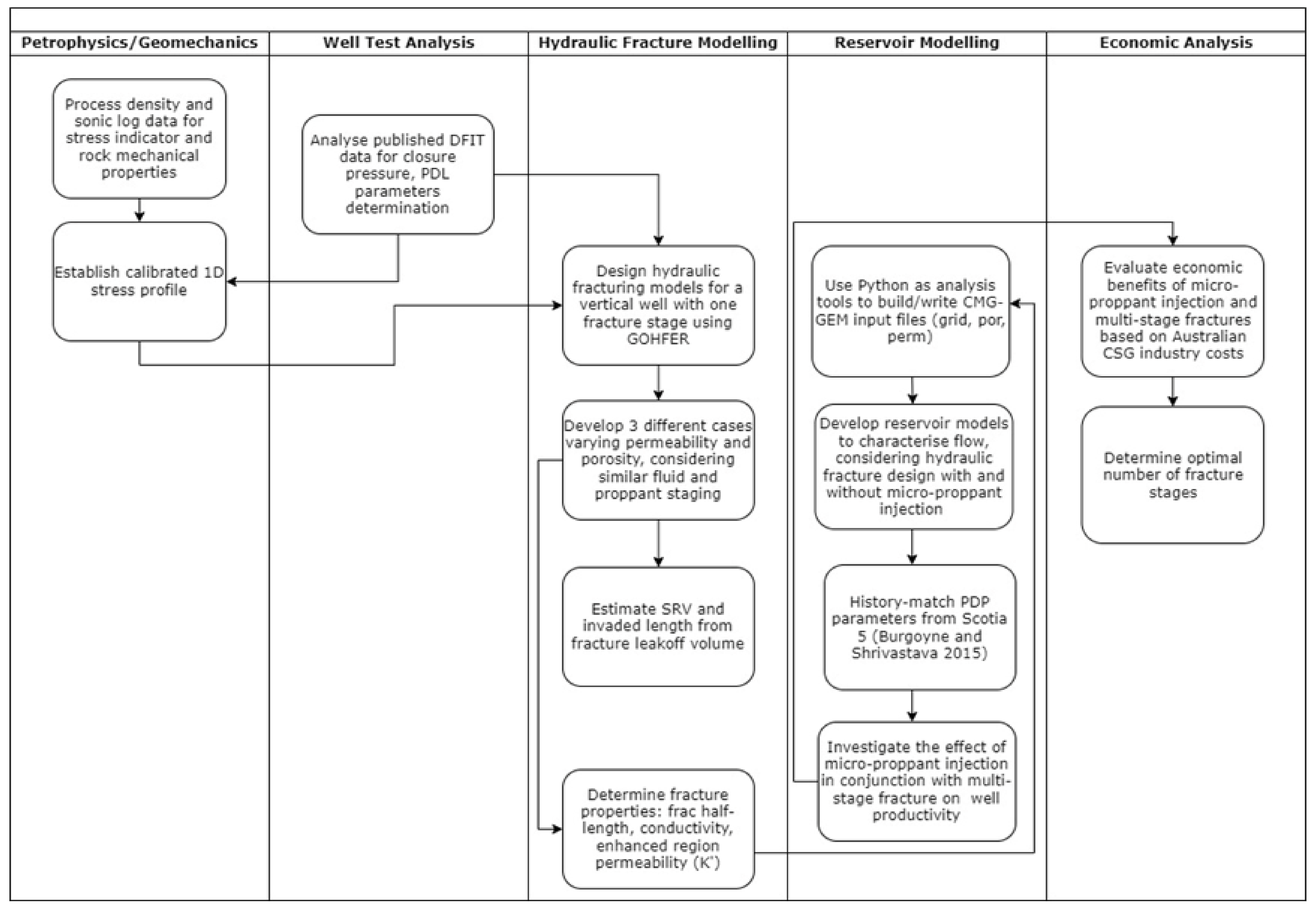

Fig 1: Integrated workflow for evaluation of the effectiveness of micro-proppant injection coupled with horizontal well, multi-stage fractures.

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Table 1: Input and history-matching parameters (base case).

Parameters	Unit	Value
Coal thickness	m	4.6
Porosity	fraction	0.01
Rock compressibility	psi^{-1}	0.00185
Initial matrix pressure	psi	1100
Initial fracture pressure	psi	1120
Permeability I-or x-direction (kx)	mD	1.41
Permeability J- or y-direction (ky)	mD	0.71
Average permeability (k_{avg})	mD	1
Vertical permeability (kv)	mD	0.1
Estimated average hydraulic fracture conductivity	mD.ft	60
Hydraulic fracture permeability (k_f)	mD	1000
Estimated fracture height (H_f)	m	4.6
Estimated fracture half-length (x_f)	m	300
Langmuir volume	m^3/ton	18.63
Langmuir pressure	psi	595
Poisson's Ratio (v)	fraction	0.37
Young's Modulus (E)	psi	500000
Volumetric strain at infinite pressure (ε_∞)	Fraction	0.02676

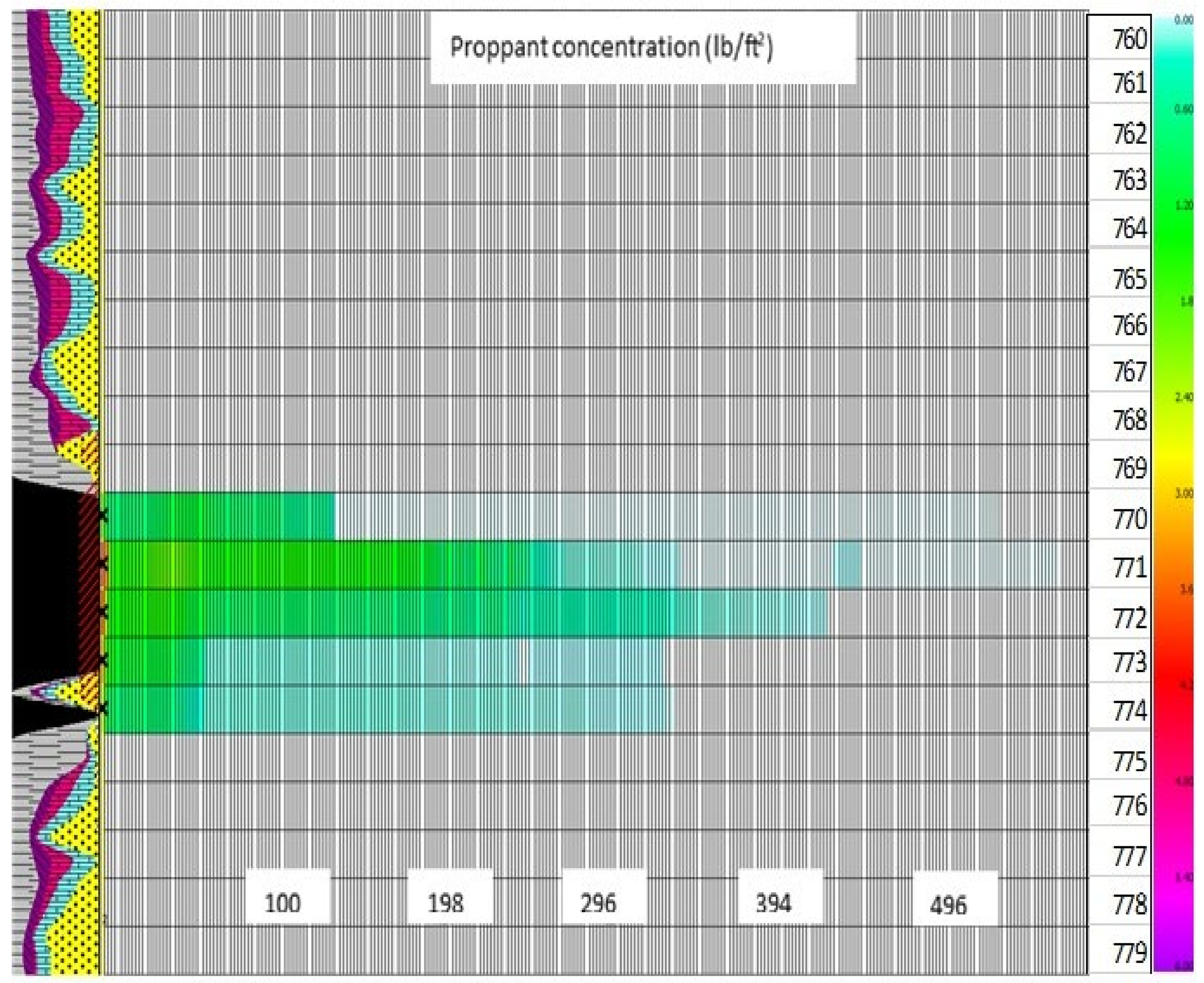

Figure 2: Resulting proppant distribution (lb/ft^2) by hydraulic fracturing treatments in targeted intervals based on a 3D planar frac model.

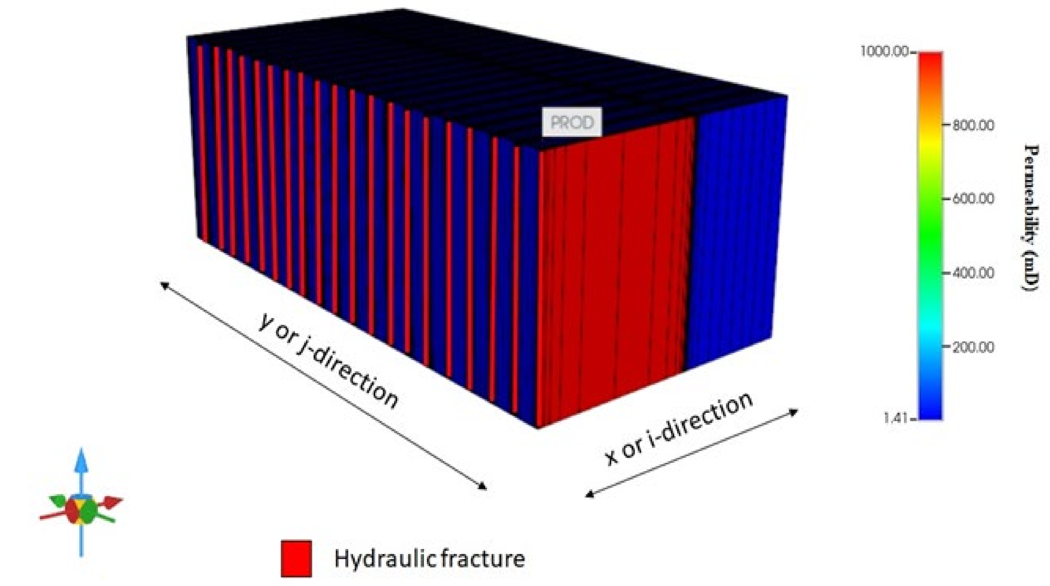

Figure 3: 3D view of the bi-wing fractured reservoir model (red: hydraulic fractured area; blue: naturally fractured area).

Results and Discussion

Modelling results

Differing leak off volumes to PDL are observable between low-and high-permeability coals, as PDL effects increase exponentially with increasing net fracturing pressures then become dominant in lower permeable coal seams. With the remaining parameters the same, low-permeability coals exhibit higher PDL and transverse leak off volumes and a shorter fracture half-length and larger SRV than high-permeability coals. Thus, the unpropped, enhanced region of permeability to potentially benefit from micro-proppant injection, is inversely proportional to permeability (Figure 4a) and fracture half-length (Figure 4b).

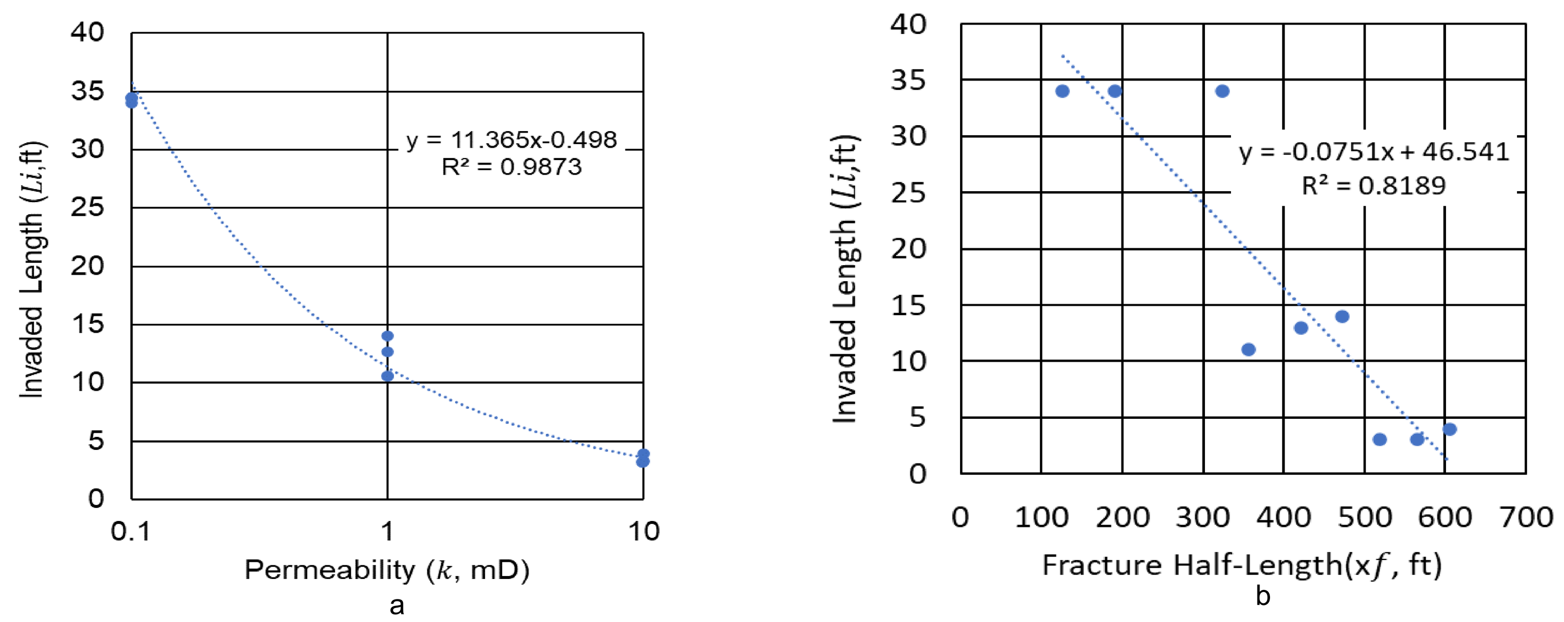

Figure 4: Pressure-dependent leak off effects in low-and high-permeability coals: (a) invaded length versus permeability and (b) invaded length versus fracture half-length

The reservoir simulation results are presented of three different scenarios based on dependent porosity and permeability relationships (i.e., porosity ranges from 0.5 to 2% and permeability varies between 0.1 to 10 mD, respectively). Varying the number of fracture stages (5, 10, 15, 20) confirms that greater gas production is observed in high-permeability coals, leading to higher estimated ultimate recovery; however, the relative increase in cumulative gas production from co-application of micro-proppants is higher in lower permeability coals. In addition, the well productivity can be increased further by increasing the number of fracture stages. The economic modelling indicated that there is a substantial improvement in discounted cash flow as a result of micro-proppants deployment (see Table 2) .

Further fidelity may be obtained by modelling fractures and micro-fractures more discretely. Further improvements in higher permeability coals may be obtained by staging separate or sequential micro-proppant treatments or by sequentially staging particles by increasing size, as originally proposed by Keshavarz, et al (2015).

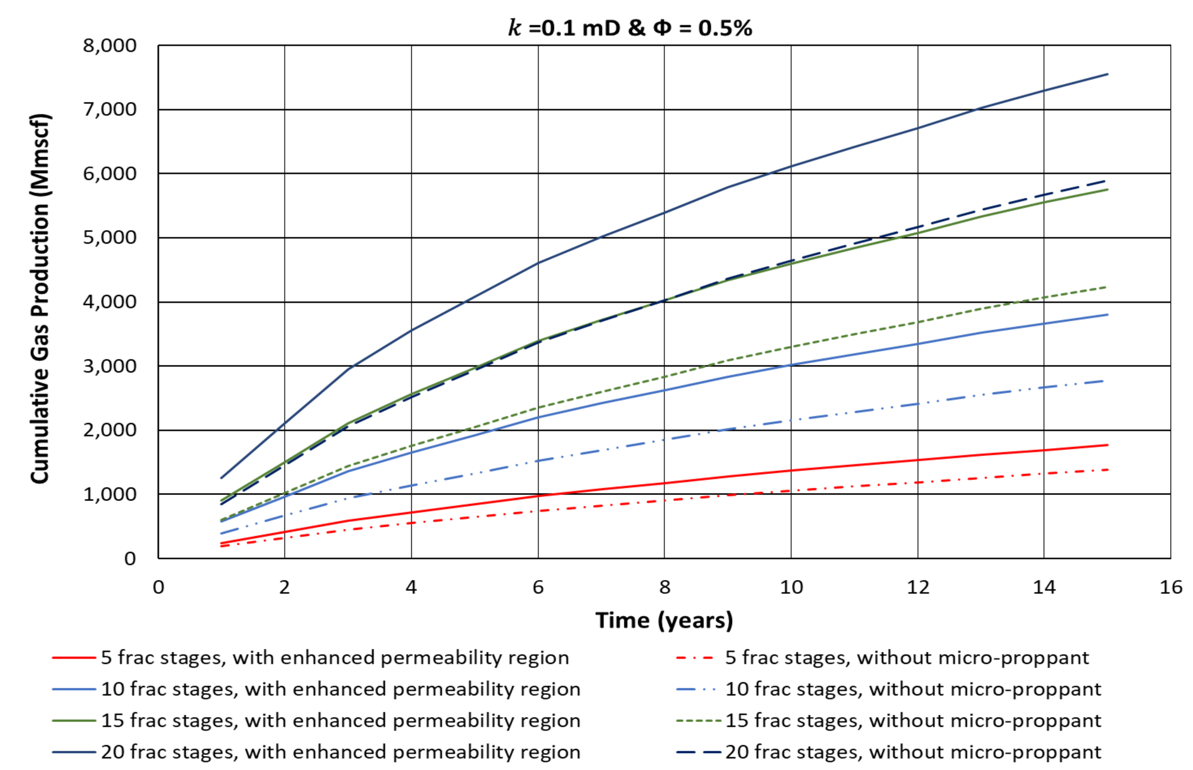

Figure 5: Cumulative gas production for varying number of fracture stimulation stages: low-permeability coals (0.1mD)

Table 2: Effect of the number of fracture stages and micro-proppants on NPV (Base case)

Number of fracture stages	Net present value [Million] (k =1 mD & Φ =1%)	
	With micro-proppant injection	*Without micro-proppant injection*
5	$1.21	$0.43
10	$12.30	$10.82
15	$21.78	$19.53
20	$31.28	$26.17

Conclusions

This study provides valuable insight into the integration of PDL/PDP data with the hydraulic fracturing design to determine the expected outcomes of micro-proppant injection. The conclusions of this study can be summarised by the following:

- PDL effects in low- and high-permeability coals differ. Less permeable coals exhibit higher PDL and transverse leak off resulting in a higher unpropped SRV available for micro-proppants. By design, the leak off volume becomes the desired treatment volume for micro-proppants. High-permeability coals have a lower SRV based on similar treatment volumes as a result of greater fracture half-lengths, overall lower leak off from reduced PDL and transverse fracture effects.
- The resulting invaded length and enhanced natural fracture system conductivity from micro-proppants, is inversely proportional to fracture half-length and permeability.
- Less permeable coals generate lower estimated ultimate recovery compared to high-permeability coals, but the relative increase in cumulative gas production post-micro-proppant injection is more significant for low-permeability coals.
- In all cases, increasing fracture stages (and lateral length) results in a larger SRV, higher EUR, and NPV.

Acknowledgements

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