

Pressure and rate analysis in unconventional reservoirs.

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A thesis submitted for the degree of MPhil

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Some of the contents of this thesis also appear in other materials associated with this research on pressure and rate analysis in unconventional reservoirs.

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Abstract

The aim of this work is to develop a realistic conceptual shale gas reservoir model that explains the observed behaviour of Haynesville wells and can predict their future behaviour.

A model developed by Kostyleva (2019) consists of a two zone repetitive element for each set of wellbore perforations. A fractured zone is in contact with the wellbore and surrounded by a matrix zone representing the rock unaffected by fracturing. The two zones have different initial permeabilities. The matrix permeability decreases as soon as its pore pressure begins to fall. The decline in fractured zone permeability starts below a threshold pressure. Later, a pseudo-skin factor is introduced and increases with time. The validation of Kostyleva's (2019) model is continued by accurately simulating the dynamic pressure behaviour of 8 Haynesville Shale wells from the period 2014 – 2016.

Two components of Kostyleva's (2019) model seem unrealistic. Any pressure drop in a region intended to represent the network of fractures around a wellbore should cause an immediate fall in its permeability. Field observations do not support the existence of an actual skin factor. Therefore, the present study proposes a new Multiple Fracture Zone (MFZ) model. Each perforation set is surrounded by several zones. Each zone represents a volume of shale containing both matrix and fractures and has a different permeability-pressure relationship. Fractures in zones nearer the wellbore contain more proppant and are less compressible. Any pressure drop decreases permeability and no pseudo-skin factor needs to be introduced.

The MFZ model has been validated by accurately simulating the dynamic pressure behaviour of 8 Haynesville Shale wells from the period 2014 – 2018.

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1 Introduction

1.1 Context

This research was performed in the context of a Joint Industry Project (JIP) on well test analysis that covers multiwell deconvolution and the interpretation of pressure and rate data from unconventional reservoirs. This work focuses on the latter and is a continuation of the work by Kostyleva (2019).

1.2 Unconventional resources

Unconventional resources, such as shale gas reservoirs, are defined as those with a permeability/viscosity ratio such that, in order for petroleum production to be commercially viable, the rock permeability or fluid viscosity must be altered (Cander, 2012). Economical rates of hydrocarbon extraction from shale reservoirs can only be achieved by pumping water and proppant into formations to create networks of induced and natural fractures, thus increasing the permeability around a wellbore (Ouenes *et al.*, February 2014).

1.3 Shale gas

The combination of horizontal drilling and hydraulic fracturing has greatly increased the profitability of oil and natural gas production from shale plays. Efforts to develop technologies for the profitable production of gas from shale rock began in the 1970s. In the 1980s and 1990s, Mitchell Energy and Development Corporation produced gas from the Barnett Shale in Texas. Their commercial success encouraged other companies enter the Barnett play and other plays such as the Fayetteville, Haynesville and Eagle Ford. In the late 2000s, the significance of the effect of shale gas production on the natural gas market began to become apparent. Shale gas production in the U.S. increased from 1.0 trillion cubic feet in 2006 to 4.8 trillion cubic feet in 2010, when it accounted for 23% of U.S. dry gas production (U.S. Energy Information Administration, 2011). In 2013, technically recoverable resources of world shale gas were estimated to be 7,299 trillion cubic feet (U.S. Energy Information Administration, 2013). Whilst the technology required to produce all these resources exists, it may not be profitable to do so, however.

1.3.1 Completion

Horizontal shale gas wells are typically completed in stages using the “plug and perf” technique. After a well is drilled and cased, the stage furthest from the surface (well head) is perforated. Fracturing fluid with proppant is then pumped into the well so that it passes through the perforations and opens up a network of fractures in communication with the wellbore. A plug is then positioned to isolate this stage from all of those closer to the surface. The process is repeated for each stage, moving along the stages in the direction of the well head. This results in a wellbore with several stages that have been perforated and are in communication with fracture networks, but that are all isolated by plugs. These plugs are therefore removed so that production can begin.

1.3.2 Production behaviour

The initial production rate of wells in the Barnett, Fayetteville, Haynesville and Woodford shales is approximately 10,000 Mscf/d (Sutton *et al.*, 2010). However, this decreases quickly. In the Haynesville, the rate can decrease by 50 – 70 % within the first 500 days of production. Well bottomhole pressure (BHP) also declines quickly during production. In the Haynesville it typically decreases from around 10,000 psia to 6,000 psia within the first 500 days of production. It continues to decline after this and starts to plateau at around 2,000 psia after approximately 1,000 days of production.

1.3.3 Difficulty simulating shale gas reservoirs

The simulation and prediction of shale gas production behaviour is made difficult by the large number of processes influencing it and their complex interactions. The low permeability of unconventional reservoirs leads to the rapid development of significant pressure gradients around the wellbore as production proceeds. Therefore, assumptions such as constant rock and fluid properties throughout the reservoir are not applicable. Fluid flows through the fracture networks that exist after wells are completed differently to how it would flow through homogeneous rock. Predicting or assessing the geometry of these fracture networks is difficult. They can include newly created fractures or natural fractures that were present before drilling. The natural fractures may be opened further by fluid pumping. The distribution of proppant within a fracture network and the nature of the proppant used affects the way fluid flows through it to the well. Proppant may settle in the lower parts of fractures. Smaller proppant grains can travel further into the network. Proppant is more likely to enter side fractures closer to the well where pumped fluid velocity is higher. As production proceeds, the conductivity of fractures is thought to decrease as confining pressure causes them to close. Proppant

can become embedded in fracture walls. Several layers of proppant may have settled between some fracture walls and this will provide additional resistance to fracture closure. Some unpropped fractures may be resistant to closure because of asperities. Closing fractures may start to accumulate shale fines which then reduce conductivity further. The parameters describing each of these processes can vary along the wellbore and to either side of it.

1.3.4 Reservoir models studied in this work

Two numerical shale gas reservoir models are studied in this work. Both have the advantage of simulating shale gas reservoir behaviour without specifically representing all of the complex processes outlined above. Instead, both use simplified representations of the reservoir consisting of homogeneous zones that are assigned pressure-permeability functions. No effort is made to model geomechanics or individual fractures. This results in a far lower computer time requirement.

One of the models was developed earlier in the Joint Industry Project by Kostyleva (2019). It consists of a two zone repetitive element for each set of wellbore perforations. A fractured zone is in contact with the wellbore and surrounded by a matrix zone representing the rock unaffected by fracturing. The two zones have different initial permeabilities. The matrix permeability decreases as soon as its pore pressure begins to fall. The decline in fractured zone permeability starts below a threshold pressure. Later, a pseudo-skin factor is introduced and increases linearly with time. Two components of Kostyleva's (2019) model seem unrealistic. Any pressure drop in a region intended to represent the network of fractures around a wellbore should cause an immediate fall in its permeability. Field observations do not support the existence of an actual skin factor.

The other model studied in this work is a new Multiple Fracture Zone (MFZ) model. In it, each perforation set is surrounded by several zones. Each zone represents a volume of shale containing both matrix and fractures and has a different permeability-pressure relationship. Fractures in zones nearer the wellbore contain more proppant and are less compressible. Any pressure drop decreases permeability and no pseudo-skin factor needs to be introduced.

1.4 Aim

The aim of this work is to develop a realistic conceptual shale gas reservoir model that explains the observed production and pressure data of wells in the Haynesville Shale and can predict their future behaviour. As in other shale gas reservoirs, such as the Barnett, Fayetteville and Woodford, horizontal

wells with hydraulic fractures are used in the Haynesville and initial well performance is approximately 10,000 Mscf/d (Sutton *et al.*, 2010). A model that accurately simulates one may therefore be applicable to the others.

1.5 Objectives

In order to meet the aim of developing a shale gas reservoir model, the two models described above will be studied with the following objectives.

1. Assess capacity of each model to history match well data from the Haynesville shale. The sensitivity of history matches to different model parameters will also be assessed.
2. Assess the minimum number of months of production data that each model must be history matched to in order for the parameters obtained by that history match to allow it to accurately simulate all subsequent production data. This will be considered as the predictive capacity of the model. The sensitivity of predictions to different model parameters will also be assessed.
3. Determine the pressure derivative response of the MFZ model. This will show how it compares to analytical models. The effect of reservoir depletion on the derivative response will also be assessed.

1.6 Papers associated with this research

The following papers were prepared during this research.

Marsden, J., Kostyleva, I., Fassihi, M. R., & Gringarten, A. C. (2017, October 9). A Conceptual Shale Gas Model Validated by Pressure and Rate Data From the Haynesville Shale. Society of Petroleum Engineers. doi:10.2118/187456-MS

Marsden, J., Kostyleva, I., Fassihi, M. R., & Gringarten, A. C. A Conceptual Model For Predicting Production From the Haynesville Shale. Hydraulic Fracturing Journal. 2018.

1.7 Summary of following chapters

The remaining chapters of this thesis are structured as follows. A review of the literature on unconventional reservoirs discusses the processes that occur during the production of shale gas and efforts to simulate it, including Kostyleva's (2019) model. The review is summarised together with the motivation for this work. The next chapter introduces the Haynesville Shale. This is the field which is used as a case study to assess the two models. The data available from it is discussed. A method

chapter describes how simulation software is used to prepare each model and lists the ways in which they will be assessed. A results and discussion chapter contains the results of these assessments for each model and discussions of them. A conclusions chapter describes the key findings of the work and its strengths and weaknesses. This is followed by recommendations for future research.

2 Review of the literature on unconventional reservoirs

2.1 Development

2.1.1 Fracture network geometry

The region around a shale well is geomechanically and geologically heterogeneous. Therefore, stimulation is unlikely to create a symmetrical fracture perpendicular to the wellbore. Instead, fractures have different lengths on each side of a wellbore and their orientation is influenced by the stress the rock is under. Geomechanical simulation can predict the pattern of strain around a well that would be created by a given fracturing strategy. Fracture half lengths would be greatest in the high strain areas (Ouenes *et al.*, 2015).

Rock mechanical properties such as Young's Modulus and Poisson's Ratio affect fracture propagation and can exhibit anisotropy, leading to the formation of complex high conductivity fractures. When a fracture causing load acts parallel to a plane of isotropy, a clean, plane-like fracture is likely to form. On the other hand, more complex fractures are created when the load acts perpendicular to planes of isotropy (McGinley *et al.*, 2015).

Virues and Ehiriudu (2016) assessed the efficacy of an unconventional complex fracture propagation model (UFM), capable of simulating the propagation of a complex network of interacting hydraulic and natural fractures, by applying it to the Horn River formation. Well log and core data was used to build a geological model. Natural fractures were represented by a discrete fracture network. The UFM was then used to predict the fracture network that would result from the known fluid and pumping data and completion details. The prediction was matched to microseismic events recorded during stimulation by altering the discrete fracture network and stress field. Under BHP control, simulation using the final model achieved a reasonable match with actual production data.

Ouenes *et al.* (2015) converted a model based on symmetrical fractures to one with asymmetric half-lengths predicted by a strain map for an Eagle Ford well. Permeability decreases rapidly away from the wellbore in unconventional reservoirs. In their study, they used two different expressions for stimulated permeability as a function of strain and distance from the wellbore, one for the near- well region, and one elsewhere within the fractured region.

Sharma and Manchanda (2015) presented evidence for the existence of small induced unpropped fractures around the primary fractures of most unconventional wells and concluded that they affect production and close over time.

Sani et al. (2015) used tracers, pressure data and production data to assess the effects of different completion strategies of new horizontal wells drilled in Haynesville Shale leases which already contained depleted wells. Fluid tracer results showed communication between new wells. They also revealed that completion contributed more to the fracture network when more fluid and proppant was used. They concluded that planar fractures are more likely to develop in depleted areas, whereas more complex fractures would tend to develop where there is no depleted area for fracture energy to propagate into, such as in rock at initial conditions or near an old well that has been charged to high pressure.

2.1.2 Proppant and its distribution within fracture networks

Fredd *et al.* (2001) carried out experiments to assess the conductivity of fractures in cores of the East Texas Cotton Valley Sandstone. When no proppant was used, fracture surfaces had to be offset in order for asperities to maintain conductivity. When proppant was used, the characteristics of the proppant and formation determined whether the conductivity was asperity or proppant dominated. Because asperity dominated conductivity is determined by formation characteristics, which can be uncertain, the use of a high-strength proppant to achieve a proppant dominated conductivity can be desirable. Proppant use creates superior fracture conductivity and this superiority compared to unpropped fractures persists as effective closure pressure rises (Fredd *et al.*, 2001). If the amount of proppant used in a typical slickwater treatment were to be distributed evenly throughout a complex fracture network, production similar to that from an unpropped fracture network would be expected. However, the fact that stimulation using proppants tends to yield better results suggests a non-even distribution (Cipolla *et al.*, 2010). Blyton *et al.* (2015) combined their own approach to simulating particles flowing through a fracture with a fluid and a fracturing simulator to model proppant transport in a way that accounted for geomechanics and fluid flow. This predicted much smaller propped fracture lengths than current standard assumptions. Xu *et al.* (2010) used geomechanical, treatment and microseismic data to characterize the hydraulic fracture networks formed around Barnett Shale gas wells and then simulated the distribution of proppant within them for one lateral. Proppant was found to settle near the wellbore and form banks in the lower parts of fractures, propping less than 10% of the fracture surface area as a result.

Enriquez-Tenorio *et al.* (2019) found that for both propped and unpropped shale fractures, conductivity declines exponentially with closure stress. Rock properties such as brittleness and Poisson's ratio had little effect on the conductivity of propped fractures, which instead was mainly determined by proppant size and loading.

Further away from the wellbore, the velocity of proppant laden fluid is lost so it is less likely to enter side fractures (Dayan *et al.*, 2009). Sahai *et al.* (2014) pumped sand slurry into different slot arrangements at low pressures to assess proppant distribution in fracture networks. Proppant was observed to enter secondary slots either by falling from the primary slot or, if the pump rate was high enough, by flowing directly into secondary slots. Smaller proppant particles were found to travel further into the network and the authors concluded that, in the field, this segregation of particles by size results in a higher fracture conductivity in parts of the network closest to the wellbore. The intermittent sweep stages often used in slickwater treatments were imitated by pumping water alone and resulted in the creation of a proppant free zone near the perforations. Roy *et al.* (2015) 3D printed plastic flow cells with the fracture surface features of a sample of Marcellus shale and studied proppant transport within them. The rate of proppant settling was found to decrease as the inclination of the fracture, away from vertical, increased.

Tsai *et al.* (2012) used a computational fluid dynamics model to predict proppant transport in a fracture and found a low flow rate or a high proppant particle density both caused proppant to settle closer to the well. The authors suggested pumping denser proppant after a less dense one in order to achieve an even distribution within the fracture. In their simulations, the geometry of the fracture remained constant during flow and its tortuosity and surface roughness were ignored. Simulations by Kong *et al.* (2015) found that there was an optimum proppant diameter for maximising well productivity and that this diameter was smaller for less permeable reservoirs. When using combinations of proppant sizes to maximise productivity, an optimum volume proportion was observed. Increasing proppant density always lowered well productivity and this effect was more pronounced in less permeable reservoirs.

2.2 Production

2.2.1 Fracture closure and variation in permeability during production

Chen, C. *et al.* (2015) researched the effect of stress on a fracture/proppant system. Fractures with proppant were created in two Marcellus Shale core plugs. In one, bedding planes were perpendicular to the fracture. In the other, they were parallel to it. For each plug, stress was applied to close the fracture whilst the structure of the fracture and matrix was imaged. A lattice Boltzmann simulator was used to obtain permeability estimations. When bedding planes were perpendicular to the primary fracture, microscopic fractures were created in the matrix surface at an effective stress of 3,000 psi. At this stress, primary fracture permeability had fallen from 10^4 darcies to 10^2 darcies and matrix bulk permeability had risen from 10^{-6} darcies to 10^2 darcies. On the other hand, when bedding planes were parallel to the fracture, an effective stress of 6,990 psi was required to create microscopic matrix

fractures. At this stress, primary fracture permeability had again fallen from 10^4 darcies to just over 10^2 darcies and matrix bulk permeability had risen from 10^{-6} darcies to 10^2 darcies.

Alramahi and Sundberg (2012) carried out experiments to study how proppant embedment and fracture conductivity in shale are affected by confining stress. In shale samples with a high clay content (48% or 52%), proppant embedment increased rapidly in the early stages of rising stress but later, the rate of embedment slowed. In samples with lower clay contents, embedment increased steadily with rising stress but at a lower rate. The authors also measured propped fracture conductivity as closure pressure increased for shale samples of different compliances. For all, a roughly linear relationship between closure pressure and the logarithm of normalized fracture conductivity was observed. However, the data in their plot appeared quite similar for all samples at closure pressures below 2,500 psi.

Ingraham *et al.* (2015) analysed micro computed tomography scans of a propped fracture in a shale core plug at reservoir conditions (75°C, 20.7 MPa). While they observed some bubbles trapped in the proppant pack, an occurrence they felt might occur during natural gas production, they concluded this should not affect fracture permeability significantly because bubbles would be limited to low flow rate regions. After 18 hours, the authors observed shale flakes clogging flow paths, fractured proppant grains and proppant embedment. These phenomena became more pronounced as time went on. The authors also commented that, since the maximum spacing between fracture surfaces was found to decrease less than the minimum spacing, the presence of proppant was causing uneven fracture closure.

Zhang *et al.* (Oct. 2014) found that the softening effect of water on shale led to greater proppant embedment and contributed to an 88% loss of fracture conductivity in a sample of Barnett shale under a constant confining pressure of 4,000 psi. They also simulated the effect of proppant embedment alone on fracture conductivity and found that the rate of conductivity decline due to increasing grain embedment volume ratio fell as embedment progressed. Their simulations also suggested that the presence of more than one layer of proppant between fracture surfaces achieves a better maintenance of conductivity as embedment proceeds.

Gupta *et al.* (2019) placed proppant packs of 2 lb/ft² and 4 lb/ft² between metal plates and studied the effect on permeability of an axial load of 5,000 psi. The decline in permeability for the low and high concentrations was 98% and 60% respectively.

Zhang *et al.* (2014 August) studied the behaviour of natural and induced fractures in Barnett shale samples under closure stress. The presence of porous infill material in unpropped natural fractures

was found to give them a higher conductivity than unpropped aligned induced fractures, across a range of closure stresses. Among induced fractures, unpropped displaced fractures could exhibit higher conductivities than propped displaced ones at low closure stresses but lost this advantage at higher stresses, because the unpropped ones were more stress sensitive due to rock failure. Propped aligned fractures were found to be more conductive and less stress sensitive than unpropped ones. Increasing closure stress caused an exponential decline in conductivity for displaced or aligned propped induced fractures. Propped fracture conductivity increased with increasing proppant size and concentration.

McGinley *et al.* (2015) compared horizontal and vertical propped fracture conductivity in outcrop samples of Marcellus Shale. They concluded the conductivity experienced exponential decay with increasing closure stress and that conductivity was independent of fracture orientation when mechanical properties were isotropic.

According to poroelastic theory: Effective stress = stress – (Biot coefficient × pore pressure). Therefore, depletion increases the effective stress in a formation (Okouma *et al.* 2011).

Okouma *et al.* (2011) used a coupled geomechanical simulator to model stress changes in the Haynesville Shale for various constant BHP scenarios. Stress was found to be greatest near fractures and when BHP was lower. Differences between the stress maps for different scenarios became more pronounced as time progressed. The authors suggested that, for different drawdown scenarios, a single reservoir could exhibit different Yilmaz *et al.* (1991) permeability moduli, γ (equation 1).

$$\gamma = \frac{1}{k} \frac{dk}{dp} \quad (1)$$

When history matching production data, Okouma *et al.* (2011) found different permeability moduli for restricted and unrestricted rate wells. This raises the question of whether the presence of two zones, each with their own pressure-permeability function, in a model can simulate the variation in reservoir responses to different drawdowns.

2.2.2 Stress and the effects of different drawdown schedules

Shale gas reservoirs exhibit dual porosity/permeability behaviours and they are subjected to stress from overburden, tectonic forces and pore pressure. Whilst stress alone cannot completely eliminate fracture conductivity, conductivity is difficult to maintain. (Ali and Sheng, 2015)

Ali and Sheng (2015) simulated production from a Haynesville Shale gas well. This involved the generation of a compaction table to give the reduction in fracture conductivity with increasing confining stress. The compaction table generated in the process of history matching was not in

agreement with that given by a single correlation, which underestimated the loss of permeability at late times. Geomechanical effects caused bottom hole pressure to decline quickly. When different initial production rates were simulated, significant differences in cumulative production did not persist for long into production. This was attributed to fracture permeability falling and making the well unable to maintain a high rate of production.

The use of compaction tables that simply assign a fracture conductivity to each pore pressure fails to account for the fact that the manner in which a pore pressure is reached influences the reservoir conditions that will exist when it is reached and this will in turn influence the effective stress on fractures. The effective stress controls fracture conductivity. If the Biot coefficient is assumed to equal 1, the effective normal stress on a fracture is the difference between the total normal stress acting on it and the pore pressure within it. It is this effective stress that acts to close the fracture and reduce the permeability within it (Wilson, 2015). Wilson (2015) used coupled geomechanics flow modelling to compare the impact on recovery of different drawdown and proppant distribution scenarios. Gradually reducing well pressure, instead of immediately making it very low, gave the reservoir time to deplete and thus reduced the peak effective stress on a fracture during a period of production but did not lead to significant increases in estimated ultimate recovery (EUR). The existence of a pinch point near the well, however, was found to greatly reduce EUR. In this scenario, a gradually reducing well pressure alleviated much of its effect. Propping a natural fracture which intersected a primary did not greatly improve EUR.

Tabatabaie *et al.* (2015) researched the importance of drawdown management in the context of pressure dependent permeability. They modelled flow through a matrix, flow through a matrix with a stimulated reservoir volume (SRV) and flow through a matrix with a propped fracture. So long as permeability was taken to be a function of pressure, production rate always increased as well flowing pressure was reduced. When permeability was set as a function of well flowing pressure only, for given SRV and propped fracture configurations, decreasing the well flowing pressure increased the production rate until it reached a maximum, beyond which any further decrease in well flowing pressure caused the production rate to decline. In these situations, their model predicted that adjusting well flowing pressure over time to maintain the maximum possible rate during a period of production could maximise ultimate recovery.

Hydraulic fracture compressibility declines with increasing effective closure stress (Yao *et al.*, 2016). Yao *et al.* (2016) modelled a multi-stage fractured horizontal shale well with fracture conductivities that varied with closure stress. They derived an expression for fracture conductivity based on effective stress change and the variation in fracture compressibility that would accompany it. The expression

was validated using experimental data. Assuming constant compressibility would lead to an underestimation of conductivity for a given effective stress. The expression was combined with models for fluid flow in both the matrix and fractures using a function that relates stress change and pore pressure. To obtain the pressure field caused by flow through the fractures, their changing conductivity was discretized in time and space. The model was run assuming a constant BHP. A higher initial fracture compressibility with a low compressibility decline led to lower production rates. The authors concluded that higher initial conductivity was more resistant to conductivity decline than longer fracture length. They commented that high kerogen content in shale increases the stress changes caused by pore pressure decline during production and therefore exacerbates fracture conductivity loss and lowers production rates.

2.2.3 Skin factor and shale fines

The existence of a region, around the wellbore, that provides additional resistance to flow results in an additional pressure drop as fluid passes into the well. Alternatively, a stimulated well can have a decreased pressure drop near the well. The skin factor, S , is a dimensionless version of the pressure drop attributable to these skin effects. In the case of a reservoir with homogeneous behaviour (Gringarten, 1984), it is positive in the case of a damaged well and negative when a well is stimulated (Van Everdingen, 1953). Fractures can exhibit a skin effect. Fracturing fluid loss can damage the formation around the fracture whilst the crushing of proppant can create a damaged region inside a fracture near the wellbore (Cinco-Ley and Samaniego-V, 1981).

Zhang *et al.* (2015) conducted lab experiments to study a variety of factors thought to affect shale fracture conductivity. They concluded that clay content is the main reason for the conductivity loss of shale fractures in the presence of water and attributed this to swelling clays and fines generation. Shale fines are much smaller than proppant grains or crushed proppant. Zhang *et al.* (2015) found 70% of shale flakes they measured had diameters less than 15 μm . If pore throats inside a fracture become small enough, therefore, shale fines could become trapped and reduce conductivity. To assess this effect, Zhang *et al.* (2015) reversed the flow direction of water through a propped fracture after its conductivity had fallen from 87 md-ft to 4 md-ft. The aim was to release fines trapped in pore throats and thus temporarily restore some conductivity, until they were trapped again. They concluded fines had caused 12 – 20% of the conductivity reduction. The experiment was carried out under a constant closure stress of 4,000 psi.

Zeinijahromi *et al.* (2012) derived equations describing high velocity gas flow in a low permeability formation, the detachment of fines particles, fines particle movement and fines capture by small pore spaces due to size exclusion. The resulting analytical model for steady state, or constant production

rate, flow showed fines particles would accumulate proportional to time. The authors concluded that the skin factor would grow linearly with the amount of fines produced or the time of gas production. The model was matched to a field example of productivity decline but the authors commented that further validation was necessary.

2.2.4 Refracturing/restimulation

Malpani *et al.* (2015) reviewed data from restimulation treatments performed in the Eagle Ford and Haynesville shale plays and performed simulations of production following restimulation treatments. They concluded that the restimulation of properly selected wells could increase recovery and that restimulating existing depleted wells can protect them from the adverse effects of frac hits they will experience during the completion of new wells. Among the Eagle Ford wells considered, production after refracturing varied between 31 % and 76 % of initial production. Restimulating closely spaced wells was found to be of minimal benefit.

2.3 Data analysis

2.3.1 Flow regimes observed in unconventional reservoirs

In unconventional reservoirs, radial flow is unlikely to occur during the maximum realistic duration of a well test. Other flow regimes around fractured wells can appear within very short timeframes, however, and it can therefore be beneficial to sample build up data every second (Vera and Ehlig-Economides 2014).

Cheng (2011) used a numerical model to simulate a horizontal gas well with multiple identical transverse fractures in a reservoir with properties based on those of the Marcellus Shale. Fractures were evenly spaced, considered to be of finite conductivity and represented by groups of narrow gridblocks. The initial version of the model did not include a stimulated zone around fractures, stress dependent fracture conductivity or gas desorption. Its pressure transient response suggested a sequence of five flow regimes. Radial flow inside the fractures, with some linear flow into them, was followed by bilinear flow. This preceded linear flow to the fractures from the inner reservoir. Next, a quasi-steady state regime, dominated by interference between fractures, was observed. It produced a slope of 0.88 and the author commented that it was similar to pseudo-steady state flow because it arose from the depletion of the inner reservoir with almost no contribution from the outer reservoir. At late time, linear flow towards the entire wellbore-fractures complex occurred. Model features were added and/or adjusted to assess the impact on the pressure transient response of the well. A lower matrix permeability extended the duration of linear flow to fractures. Reducing hydraulic fracture conductivity extended the first flow regime. The duration of linear flow to fractures decreased with

decreasing cluster spacing. The addition of a stimulated zone to represent an enhanced permeability region around hydraulic fractures due to natural and secondary fractures resulted in the replacement of the linear flow to fractures regime by a period of quasi-linear flow producing a steeper slope. Its steepness increased with the size of the stimulated zone until all the inner reservoir was considered as stimulated zone, in which case bilinear flow was followed immediately by the quasi-steady state regime. Including gas desorption had little effect on pressure transient responses but did increase EUR. Introducing a fracture conductivity ratio vs pore pressure relationship had little effect on pressure transient responses.

2.3.2 Pressure transient analysis of unconventional reservoirs

The low permeability of unconventional reservoirs leads to rapid pressure changes inside and near the wellbore. Assumptions such as constant porosity and viscosity, made when solving diffusivity equations in conventional well test analysis, are therefore not appropriate (Roadifer and Kalaei, 2015). Roadifer and Kalaei (2015) presented expressions for pseudo-pressure and pseudo-time to be used in the semi-log radial flow approximation so that it would still apply when viscosity, compressibility and porosity were assumed to vary with pressure only. This yielded reasonably accurate (0% error) permeability estimates in numerical simulations of Eagle Ford and Bakken type reservoirs. They applied a similar approach to transient linear flow and estimated permeability with an error smaller than 1%. Their methods did not account for variations in permeability with pressure, however.

Vera and Ehlig-Economides (2013) simulated the rate normalized pressure derivative responses for a horizontal well with multiple finite conductivity fractures in the context of pressure dependent permeability. When only the matrix exhibited pressure dependent permeability, as the sensitivity of the permeability to pressure increased, the apparent fracture conductivity increased whilst the apparent drainage volume decreased. When only the fractures exhibited pressure dependent permeability, so long as the sensitivity to pressure was slight, effective fracture conductivity fell. When fracture permeability was more sensitive to pressure, a response similar to that of a fracture skin was observed. A Haynesville well was among three field cases the authors then analysed. Data was available for three build ups, all of which showed a one quarter slope on the derivative. The levels of these increased during the course of the successive build ups suggesting a decrease in permeability. It was not possible to match a constant permeability model to the data so a match was achieved using a model with pressure dependent matrix permeability. Matches of similar quality were achieved with longer fracture half-lengths by increasing the sensitivity to pressure. The authors noted that a reliable estimate of fracture half-length could therefore reduce the uncertainty of the model. They also noted that, with the introduction of pressure dependent matrix permeability to a model, rather than a single

continuous drainage volume, the drainage volume is limited to those regions close to hydraulic fractures.

2.3.3 Flowback

Around 10 – 30% of flowback water is recovered from the Haynesville Shale during the first few months of production. Often, better early production is associated with less flowback (Fan *et al.* 2010). Adefidipe *et al.* (2014) analysed flowback data from 26 multi-fractured horizontal wells drilled in the Horn River basin. Instant gas and water flow was observed in early flowback suggesting the presence of free gas in the fracture network to begin with. Conventional P/Z plots were linear at early times but had eventual upward curvatures. From this, it was inferred that initial production from the fracture networks was due to fluid expansion alone, as in the case of a closed system, but that eventually this was supported by some additional drive mechanism. Contribution by the matrix or fracture closure could account for this. The plots provided by the authors from a selection of the wells they analysed display some interesting features. Using a well named EV_{R2} as an example, when the cumulative gas production had reached 1000 Mm³, the cumulative water production was approximately 800 m³. At this point, the P/Z plot for the well had an upward curvature, indicative of a drive mechanism in addition to and supporting production by the expansion of free fluid, and the Gas-Water Ratio (GWR) was rising. The total injected volume during fracturing for EV_{R2} was 100,000 m³. This suggests that once production with the assistance of matrix gas contribution and/or fracture closure was underway, much of the injected fracturing fluid remained in the reservoir. It could therefore be the case that, early in the life of a well at least, the reservoir pressure around the wellbore is higher than that further away from it. This could have an effect on the manner in which changes in the reservoir related to pressure proceed and affect productivity.

2.4 Performance prediction

2.4.1 Shale capacity

The large variation in the productivity of gas wells drilled in shale formations is not accounted for by different fracing technologies. Shale well performance seems to depend more on reservoir characteristics than wellbore length and number of perforated intervals. One such characteristic is the natural fracture system. Natural fractures can be reactivated by hydraulic fracturing, enhancing its effect. The best wells in the Barnett Shale are drilled parallel to natural fractures and away from faults, which act as conduits for water and are undesirable in any shale play. The shale capacity concept aims to quantify the ability of a reservoir zone to produce hydrocarbons by considering four shale drivers. They are total organic content (TOC), natural fracture density, brittleness and porosity. If one or more drivers are below a certain value, both they, and the shale capacity are taken as zero. To estimate the

values of these shale drivers in three dimensions, seismic and well data are processed by neural networks designed to model interdependent variables. When a greater proportion of the wellbore intercepts high shale capacity regions, better well performance is successfully predicted. (Ouenes, 2014)

Newgord *et al.* (2015) used well log and 3D seismic data to create a shale capacity model of the Bakken reservoir. Two definitions of shale capacity were necessary. For the Middle Bakken carbonates, it combined brittleness and oil saturation. In the Upper and Lower Bakken Shales, it combined brittleness, porosity, natural fracture density and total organic carbon. A well relative intercepted shale capacity (RISC) was defined as the percentage of its wellbore intercepting a zero or negative shale capacity region of Middle and Upper or Lower Bakken. A linear relationship between RISC and 90 day initial production was observed, the most productive wells being those with lower RISCs.

Ouenes *et al.* (2014 February) estimated pseudo closure stress, an approximation of closure stress, around a Marcellus well and observed lower values in regions of high shale capacity. This is advantageous as it suggests fracture networks could remain open for longer in these regions. In a simulation, they assumed the SRV extended away from the wellbore by the average induced fracture half-length of 275 ft and consisted of only positive shale capacity regions intercepted by the wellbore. They concluded the matrix outside the SRV contributed to production, probably because its natural fracture system was linked to the induced one.

The shale capacity concept has been applied to the Haynesville Shale. Seismic data and well logs were integrated to create a 3D reservoir model populated by estimations of various shale drivers which were then combined to populate a shale capacity model. The drivers considered were gamma ray (a proxy for TOC), porosity, brittleness and resistivity (a proxy for fracture density). Using the shale capacity model, the RISC was calculated for two wells, Well 2 and Well 3, for which production data was known. As expected, a higher RISC was associated with the more productive well. Well 2 had a RISC of 35% and an average monthly production of 30.9 MMcf. The figures for Well 3 were 74% and 80.2 MMcf (Reagan *et al.*, 2013). It should be noted that Reagan *et al.* (2013) and Newgord *et al.* (2015) define RISC differently.

Fackler *et al.* (2014) investigated how shale capacity related to microseismic events in the Haynesville Shale. A neural network was used to determine correlations between logs of shale drivers and seismic attributes so that a 3D shale capacity model could be created. A larger spread of microseismic events was observed in high shale capacity regions, with large events occurring at their edges. The use of

microseismic was suggested to validate shale capacity models before they are used to find sweet spots and to predict stimulated reservoir volume (SRV).

When frac intervals are evenly spaced, some can be much more productive than others. Ouenes *et al.* (April 2014) used estimations of permeability inside and outside the SRV based on shale capacity, distance from wellbore, a variable equivalent half fracture length and history matching calibration constants in a dynamic model which then forecast production and reservoir pressure changes for a Haynesville gas well. The resulting EUR prediction of 6.4 Bcf was higher than that predicted by traditional decline curve analysis (4.23 Bcf). The model also predicted an irregular distribution of pressure changes around the wellbore. A greater pressure drop was forecast to the side of the well with the higher shale capacity. This would suggest a wider spacing of wells to that side would be preferable to simply spacing wells regularly (Ouenes *et al.*, April 2014).

An advantage of the shale capacity approach is that it uses well log and seismic data, both of which are available early in the development of a field. Additionally, RISC can be used to predict which wells shall be more productive. A limitation of shale capacity, however, is that its definition may need to be adapted for each field it is applied to.

2.4.2 Higher permeability zones around clusters

High horizontal stress anisotropy leads to the creation of a narrow fracture field when a reservoir is stimulated. Low horizontal stress anisotropy leads to the creation of a complex and sprawling fracture network instead. Microseismic measurements from the Haynesville Shale suggest the creation of complex fracture networks (Fan *et al.* 2010). In a simulation by Fan *et al.* (2010), the complex fracture networks created in the Haynesville were represented by a permeability enhanced area (PEA) around each perforation cluster. This approach matched production and pressure data for 30 wells and simulating flow through a PEA has the advantage of requiring less computing power than simulating flow through a complex fracture network. However, the authors did require fracture modelling to determine how far away from the wellbore each PEA should extend.

2.4.3 The influence of confinement stress on permeability and fracture conductivity

Hao *et al.* (2015) modelled a 17-fracture stage Haynesville appraisal well using nine different models:

- Two models consisted of a high permeability region surrounding the entire wellbore.
- Five models consisted of high permeability regions around fractures so that some of the wellbore was in contact with low permeability matrix

- Two models allowed fracture locations and properties (such as half-length and conductivity) to be specified individually. One of these, model 9, modelled the influence of confinement stress on formation permeability and fracture conductivity separately so that the two could differ.

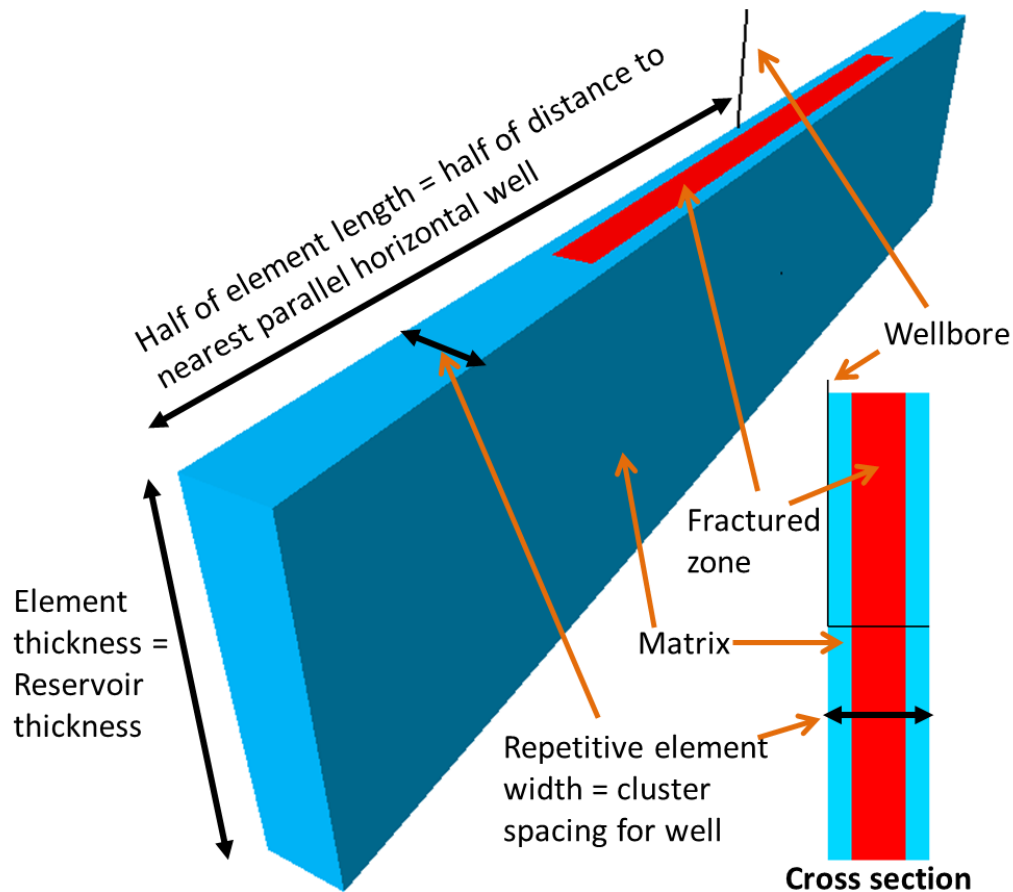
Each model was history matched to 18 months of initial production and flowing pressure data. The ability of the models to accurately predict data obtained in the subsequent 15 months was compared. Model 9 was found to produce the most accurate forecast. The authors comment that models which assume uniform fracture properties along a wellbore may be too idealized for adequate performance prediction. However, a model with uniform fracture properties but that models the influence of confinement stress on formation permeability and fracture conductivity separately so that the two can differ is not assessed.

2.5 Previous advances from the Joint Industry Project

2.5.1 Kostyleva's (2019) model

In the numerical model developed by Kostyleva (2019), each perforation cluster along a horizontal wellbore and the reservoir surrounding it is represented by a repetitive model element that comprises two reservoir regions with different initial permeabilities and different pressure-permeability functions. In Fig. 1, the enhanced permeability region representing the network of fractures (the fractured zone) created by stimulation is shown in red and the surrounding matrix region (the matrix zone) is shown in blue. The lateral limits of each repetitive element recreate the effects of no flow boundaries assumed to exist halfway between wells and halfway between perforation intervals as a consequence of their simultaneous productivity. The upper and lower limits of each repetitive element represent the upper and lower limits of the reservoir.

Figure 1: Single repetitive element of Kostyleva's (2019) model. Enhanced permeability region representing fracture network around horizontal wellbore shown in red. Surrounding matrix region shown in blue. The black line represents the wellbore.



The pressure-permeability functions are used to update the permeability at each point in the reservoir as the pressure field changes during production.

The permeability of the matrix zone starts to decline soon as the pore pressure of the matrix begins to fall. The permeability of the fractured zone only starts to decline after the pressure within it has fallen by a certain amount. Later on during a simulation, a pseudo-skin factor for the well is introduced and increases, from zero, linearly with time.

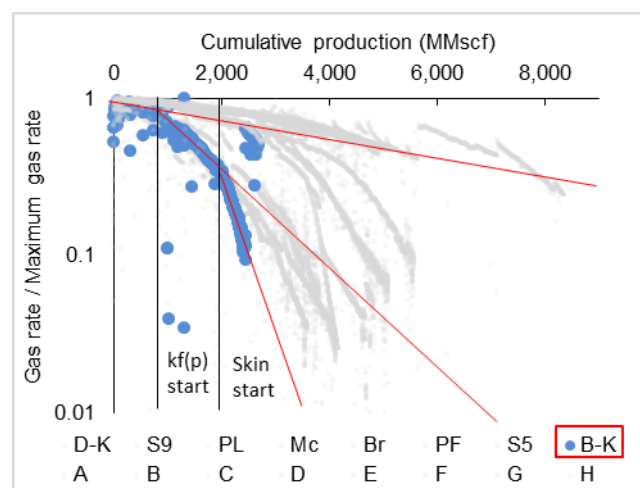
The perforation cluster is represented by a single perforation extending for 1 m at the centre of the element. The horizontal part of the wellbore is midway between the upper and lower limits of the element and is parallel and equal in length to shortest side of the element. Equal production of gas from each repetitive element is assumed, as is equal BHP at all clusters.

To begin its validation, Kostyleva (2019) matched their model to production and pressure data from 12 Haynesville Shale wells recorded over a period of approximately 5 years. The following conclusions were made.

1. The model accurately described the behaviour of wells used to validate it.
2. The model integrates the pressure dependent behaviour of the matrix zone by using the same pressure-permeability function for all wells. This function was obtained from measurements on core samples.
3. History matching of production data is required to determine the pressure dependent behaviour of the fractured zone for each well and the onset and trend of the pseudo-skin factor.
4. On a cumulative production versus normalised rate plot, most wells follow the same initial pseudo-linear trend as the matrix zone permeability declines. This is followed by a second apparently linear trend when the fractured zone permeability decreases. Finally, there is a third linear trend when pseudo-skin effects dominate. These trends are shown as continuous red straight lines for well B-K in Fig. 2.

Once the onset and trend of the pseudo-skin factor have been established by history matching, the model accurately simulates BHP under observed rate control. However, establishing these parameters requires up to 3 years of data.

Figure 2: Cumulative production versus normalised rate plot for a selection of validation wells. Continuous red lines are used to highlight trend changes for well B-K. “kf(p) start” represents the onset of fractured zone permeability decline. “Skin start” represents the introduction of a pseudo-skin factor.



2.5.2 Studies supporting Kostyleva's (2019) model

Some elements of Kostyleva's (2019) model are supported by the literature. Work by McGinley *et al.* (2015) and Sharma and Manchanda (2015) supports the existence of complex fracture networks around a well. The PEA approach successfully used by Fan *et al.* (2010) to represent complex fracture networks is similar to Kostyleva's (2019) use of a fractured zone.

Reservoir depletion increases the effective stress in a formation (Okouma *et al.* 2011) and closure stress decreases fracture permeability (Chen, C. *et al.* 2015). This is consistent with Kostyleva's (2019) assumption that the fractured zone permeability should decrease as production proceeds.

Kostyleva's (2019) model requires the introduction of a pseudo-skin factor when BHP is below 2000 – 4000 psia. For all the wells to which the model was applied, the skin factor continued to increase linearly with time from its onset and did not plateau. The onset of the skin effect only occurred late in the simulations, after the permeability of both the enhanced and matrix regions had declined. At this stage, the pore throats inside fractures may have decreased in diameter and become capable of trapping shale fines (Zhang *et al.* 2015). The pseudo-skin may represent the trapping of shale fines in the propped region of the fracture network near the wellbore, starting once closure stress has sufficiently decreased pore throat diameters.

2.5.3 Studies contradicting Kostyleva's (2019) model

In Kostyleva's (2019) model, the permeability at each point in the fractured zone does not start to decline until the pressure at that point has decreased by an amount determined by history matching. Several studies, such as those by Alramahi and Sundberg (2012) and Zhang *et al.* (2014 August), have shown that any increase in the closure stress acting on a fracture results in a decrease in its conductivity. Since depletion increases the effective stress in a formation (Okouma *et al.* 2011), any pressure drop in a region intended to represent the network of fractures around a wellbore should cause an immediate fall in the permeability of that region.

The pseudo-skin factor in Kostyleva's (2019) model may be unrealistic. Fractures can exhibit a skin effect. Fracturing fluid loss can damage the formation around the fracture whilst the crushing of proppant can create a damaged region inside a fracture near the wellbore (Cinco-Ley and Samaniego-V, 1981). However, the skin effect in Kostyleva's model is introduced some time after fracturing and proppant crushing should be representable by the decrease in fractured zone permeability, as should the trapping of shale fines. In addition to this, field observations do not support the existence of a skin factor caused by salt deposition or perforation plugging.

2.6 Summary of literature review and motivation for this research

The region surrounding a shale gas well is often geologically and geomechanically heterogeneous so the creation of symmetrical fractures perpendicular to the wellbore is unlikely. The mechanical properties of the rock determine whether plane like fractures or sprawling and complex fracture networks are formed.

Proppant is not evenly distributed in fractures or fracture networks. It settles near the wellbore and in the lower parts of fractures. Sometimes, less than 10% of fracture surface area is propped. Smaller proppant travels further into a fracture network. However, away from the well, the velocity of pumped fluid is decreased so proppant is less likely to enter side fractures. Small induced fractures often remain unpropped.

The conductivity of propped fractures depends more on proppant than rock properties. Propped fracture conductivity increases with proppant size and concentration.

Depletion increases the effective stress in a formation and increasing closure stress causes an exponential decline in the conductivity of propped induced fractures. Hydraulic fracture compressibility declines with increasing effective closure stress. More proppant, and the presence of several layers of proppant between fracture surfaces helps to preserve conductivity. Data from successive build ups in a Haynesville Shale well has been analysed and found to suggest that permeability decreases as production proceeds.

The shale capacity concept has been used to predict which shale gas wells will be most productive based on factors such as brittleness and natural fracture density. Shale gas well behaviour has been successfully simulated using regions of increased permeability to represent complex fracture networks. Modelling the influence of confinement stress on formation permeability and fracture conductivity separately so that the two can differ has also successfully simulated shale gas well behaviour.

A model developed by Kostyleva (2019) consists of a two zone repetitive element for each set of wellbore perforations. A fractured zone is in contact with the wellbore and surrounded by a matrix zone representing the rock unaffected by fracturing. The two zones have different initial permeabilities. The matrix permeability decreases as soon as its pore pressure begins to fall. The decline in fractured zone permeability starts below a threshold pressure. Later, a pseudo-skin factor is introduced and increases linearly with time. This model was matched to production and pressure data from 12 Haynesville Shale wells recorded over a period of approximately 5 years. The pseudo-

skin factor and the delay in fractured zone permeability decline could be considered unrealistic, however.

The above suggests that whilst the behaviour of shale gas reservoirs is complex, models comprising adequate approximations of the most influential processes can simulate them accurately and efficiently. This is the motivation for this work, which aims to continue the development of a realistic conceptual shale gas reservoir model that explains observed production and pressure data and predicts future behaviour.

3 Field under study

3.1 Haynesville Shale

In this work, data collected from the Haynesville Shale is used to assess different approaches to modelling shale gas reservoirs. It covers an area of around 5.8 million acres at a depth ranging from 10,300 ft in the northwest to 14,000 ft in the southeast. The Haynesville Shale lies underneath the Bossier Shale and above the Smackover Limestone. The Haynesville Shale is a dry gas reservoir and horizontal drilling began in 2007. (Fan *et al.*, 2010; Parker *et al.*, 2009; eia.gov).

3.1.1 Applicability of work to other shale gas plays

As in other shale gas reservoirs, horizontal wells with hydraulic fractures are used to produce from the Haynesville. Initial well performance is approximately 10,000 Mscf/d and similar to that in the Barnett, Fayetteville and Woodford shales (Sutton *et al.*, 2010). This suggests models developed during the Joint Industry Project which accurately simulate Haynesville well behaviour may be applicable to other shale gas plays. However, the pressure and temperature of the Haynesville are both unusually high compared to other shale plays (Thompson *et al.*, 2010). Additionally, the desorption capacity of the Haynesville is less than that of other reservoirs. Eshkalak and Aybar (2015) derived expressions to model the change in porosity of shale matrix resulting from desorption and rock compaction as reservoir pressure falls. They used an empirical porosity-permeability relationship from Raghavan and Chin (2004) and plotted their results for the Marcellus, Barnett, New Albany and Haynesville Shales based on experimentally determined desorption isotherms. For all except the Haynesville, porosity and permeability decreased as pressure was reduced until the pressure reached a certain value, below which desorption caused some of the fall in porosity and permeability to be reversed. The comparatively low capacity for desorption of the Haynesville meant that it did not exhibit a reversal in porosity and permeability decline at low pressures. Eshkalak and Aybar (2015) combined the above with an expression relating the permeability of a hydraulic fracture to pore pressure and simulated production from a horizontal hydraulically fractured well in each of the four shale reservoirs. They concluded that ignoring the effects they had modelled would result in an overestimation of recovery in all four cases.

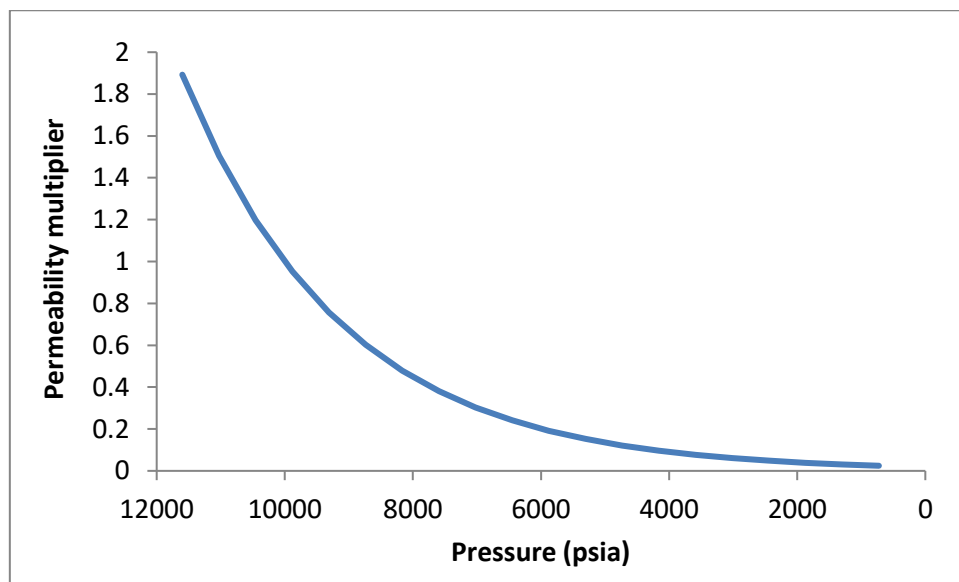
3.2 Data provided by Joint Industry Project contributors

3.2.1 Haynesville Shale rock and fluid data

A table of matrix permeability multipliers and pressures, obtained from core measurements, was available to the JIP and is described by equation 2, for pressures in psia, and shown in Fig. 6 for an initial pressure of 10,005 psia (690 bar).

$$\frac{k}{k_i} = e^{-0.0004(p_i - p)} \quad (2)$$

Figure 6: Matrix permeability multipliers for different pore pressures based on a relationship obtained from core measurements



Gas analysis was provided and included the composition given in table 1. A compressibility factor of 0.9979 at 14.696 psia and 60 °F was reported.

Table 1: Gas analysis (real gas gravity = 0.584)

Component	Mole fraction
Methane	0.968757
Ethane	0.002821
Propane	0.000129
Iso-butane	0.000015
Normal-butane	0.00002
Nitrogen	0.000757
Carbon dioxide	0.027481
Hydrogen sulphide	0.00002

3.2.2 Well data

Production, pressure and completion data from several Haynesville wells was supplied at different points during the JIP.

3.2.2.1 Well data used by Kostyleva (2019)

Kostyleva (2019) used datasets of approximately 5 years duration from 12 wells, which are described in table 2.

Table 2: Completion data (where available) for 12 Haynesville Shale wells used for model validation by Kostyleva (2019).

Well	Cluster spacing (ft)	Proppant (lbs/ft lateral length)
D-K	70	1027
PF	86	1056
S8	83	1060
H-K	63	1093
B-K	70	1149
Br	105	1149
S5	82	1308
S9	61	1512
SP	100	
OH	108	
PL	58	
Mc	79	

3.2.2.2 2014 – 2016 Haynesville Shale dataset

At the beginning of this research, completion data was supplied for eight, roughly parallel Haynesville wells (table 3), with a spacing of approximately 1,000 ft, together with production and pressure data for the period 2014 – 2016. Pressures were based on spot readings at a point in time on a given day. Spot readings of flow meters were used to estimate gas production rates. The horizontal segments of wellbores were reported to pass through the middle of the pay zone.

Table 3: Completion data for 8 Haynesville Shale wells (A – H) provided at the beginning of this research.

Well	Stages	Perforation Intervals (clusters)	Cluster Spacing (ft)	Completed Interval (ft)	Number of perforations	Lbs of proppant per ft of lateral wellbore length (lbs)
A	31	155	33	5185	930	2000
B	31	155	33	5167	930	2000
C	30	150	34	5198	900	2000
D	30	150	34	5192	900	2000
E	14	84	55	4558	504	1200
F	14	84	55	4558	504	1200
G	18	108	44	4537	626	2500
H	15	90	53	4541	540	2500

3.2.2.3 2014 – 2018 Haynesville Shale dataset

Later on during this research, additional production and pressure data from the initial 8 wells (A – H) was provided so that data from these wells was available for the period 2014 – 2018.

Descriptions of the completions of 8 more wells were also provided at this stage (table 4), along with their pressure and production data for the period 2015 – 2018.

Table 4: Completion data for 8 additional Hayneville Shale wells provided later in this research.

Well	Stages	Perforation Intervals (clusters)	Cluster Spacing (ft)	Completed Interval (ft)	Number of perforations	Lbs of proppant per ft of lateral wellbore length (lbs)
S3-1	30	137	34	4566	822	2890
S3-2	33	160	33	5299	960	3010
S3-3	33	160	34	5421	960	2870
S4-LL1	45	220	33	7267	1325	1960
S4-LL2	46	220	33	7211	1320	2050
S5-LL1	45	220	33	7148	1320	2010
S5-LL2	48	221	32	7051	1345	1890
S5-LL3	47	220	27	7351	1334	2080

3.2.2.4 Calculation of bottomhole pressures from tubing head pressures

The 2014 – 2016 and 2014 – 2018 data sets contained well tubing head pressure (THP) values. In this work, the accuracy of reservoir simulations was assessed using bottomhole pressure (BHP).

Therefore, THP values were converted to BHP values using equations 3 – 5 presented by Katz (1959) for use in the context of dry gas production and obtained from Lyons *et al.* (2016):

$$q_g = 200,000 \left(\frac{sD^5(P_{wf}^2 - e^s P_{wh}^2)}{G_g \bar{T} \bar{Z} H f (e^s - 1)} \right)^{0.5} \quad (3)$$

$$f = \left(2 \log \left[\frac{3.71}{\varepsilon/D} \right] \right)^{-2} \quad (4)$$

$$s = 0.0375 G_g H / \bar{T} \bar{Z} \quad (5)$$

In equations 3 - 5, the average temperature is the arithmetic average of the wellhead and bottomhole temperatures. The compressibility factor is evaluated at the average temperature and the average of the wellhead and bottomhole pressures.

Unless a constant compressibility factor is assumed, equations 3 – 5 must be applied iteratively. To determine whether this was necessary, a check was performed using the data from Well E since it was among the more extensive datasets.

Tubing head pressures from Well E were converted to bottomhole pressures using the parameters listed in table 5. The principle of corresponding states and the compressibility factor correlation of

Brill and Beggs (1974) were used in an iterative application of equations 3 - 5. Table 6 is a calculation of the pseudocritical properties of the reservoir fluid.

Table 5: Parameters used in equations 3 – 5 to convert tubing head to bottomhole pressures

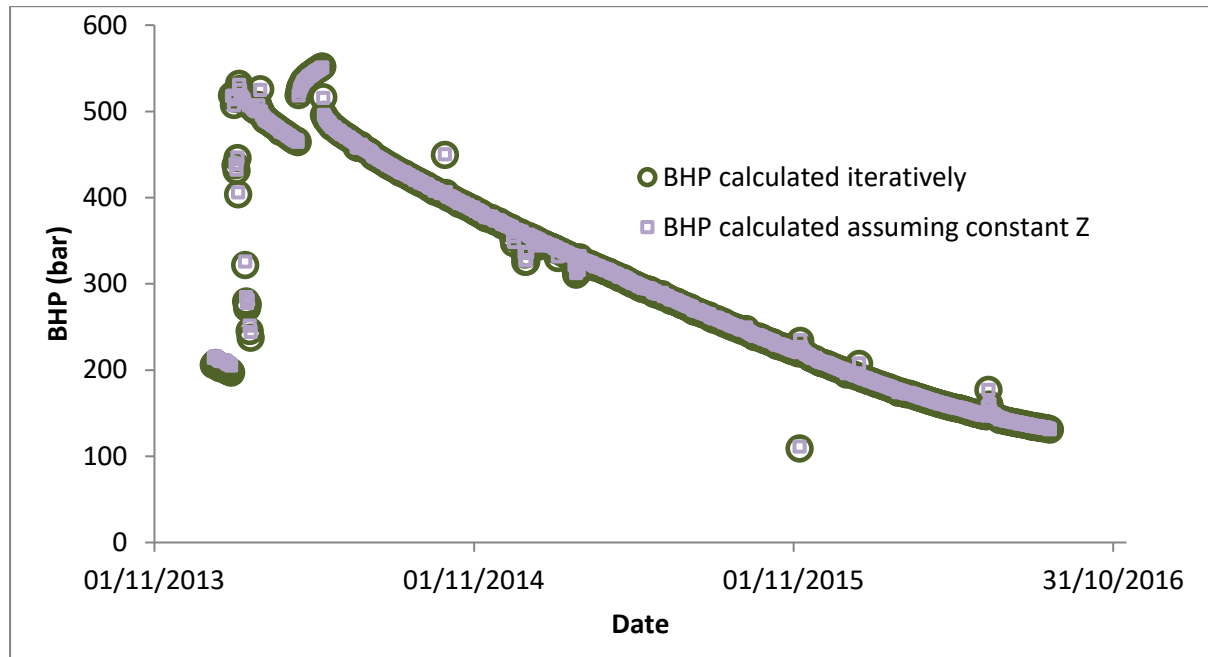
Parameter	Symbol	Value
Wellhead temperature (assumed constant)		559.67 °R
Bottomhole temperature (assumed constant)		809.67 °R
Tubing diameter (provided by JIP contributor)	D	1.995 inches
Gas gravity (provided by JIP contributor)	G _g	0.584
Bottomhole depth (provided by JIP contributor)	H	11,400 ft
Absolute pipe roughness	ε	0.0006 inches

Table 6: Pseudocritical properties of reservoir fluid found using values published by Lyons et al. (2016)

Component	Mole fraction	Critical pressure, Pa	Mole fraction * critical pressure	Critical temperature, °K	Mole fraction * critical temperature
Methane	0.968757	4604000	4460157.228	190.55	184.5966464
Ethane	0.002821	4880000	13766.48	305.43	0.86161803
Propane	0.000129	4249000	548.121	369.82	0.04770678
Iso-butane	0.000015	3648000	54.72	408.13	0.00612195
Normal-butane	0.00002	3797000	75.94	425.16	0.0085032
Nitrogen	0.000757	3399000	2573.043	126.1	0.0954577
Carbon dioxide	0.027481	7382000	202864.742	304.19	8.35944539
Hydrogen sulphide	0.00002	9005000	180.1	373.5	0.00747
		Pseudocritical pressure, Pa:	4680220.374	Pseudocritical temperature, °K:	193.9829694
		Pseudocritical pressure, psia:	678.8098026	Pseudocritical temperature, °R:	349.1693449

Fig. 7 compares the BHP values found using an iterative application of equations 3 – 5 with those found when a constant compressibility factor of 1.1 was assumed. Since the two sets of values are very similar, a non-iterative application of the equations, assuming a constant compressibility factor of 1.1, was used for all wells in this research. The highest BHP values in Fig. 7 approach 10,000 psia. This is consistent with the 9,500 – 10,500 psia (655 – 724 bar) initial reservoir pressure values found in the literature (Wilson, 2015; Ali and Sheng, 2015; Okouma *et al.*, 2011).

Figure 7: A comparison of BHP values found using an iterative application of equations 3 – 5 with those found when a constant compressibility factor of 1.1 was assumed for Well E



3.3 Data from other sources

3.3.1 Published parameters

Some of the data required to build numerical reservoir models was not available from JIP contributors. A literature review was carried out to establish a selection of parameters describing the Haynesville Shale (table 7). Based on this, the values in table 8 were selected for use.

Table 7: Published parameters describing Haynesville Shale

Parameter	Value	Reference	SPE paper number
Height (= thickness)	150 – 400 ft	Sani et al. 2015	175917
	100 ft	Wilson 2015	175029
	150 ft	Okouma et al. 2011	147623
Depth	10,500 ft – 14,500 ft	Sani et al. 2015	175917
	11,150 ft	Wilson 2015	175029
	11,160 ft	Ali and Sheng 2015	177299
	11,000 ft – 14,000 ft	Fan et al. 2010	136696
Pressure gradient	0.9 psi/ft	Okouma et al. 2011	147623
	0.7 – 0.9 psi/ft	Fan et al. 2010	136696
Temperature	300 – 350 °F	Sani et al. 2015	175917
	305 °F	Wilson 2015	175029
	325 °F	Ali and Sheng 2015	177299
	280 – 400 °F	Fan et al. 2010	136696
	360 °F	Okouma et al. 2011	147623
Porosity	6 – 15 %	Sani et al. 2015	175917
	8.5 %	Wilson 2015	175029
Initial water saturation (S_{wi})	20 – 35 %	Sani et al. 2015	175917
	30 %	Wilson 2015	175029
	20 %	Ali and Sheng 2015	177299
Fluid	Dry gas	Wilson 2015	175029
Initial pressure	9,500 psia	Wilson 2015	175029
	10,500 psia	Ali and Sheng 2015	177299
	10,500 psia	Okouma et al. 2011	147623
Matrix permeability	0.0001 md	Wilson 2015	175029
	0.0005 md	Ali and Sheng 2015	177299
	0.0015 md	Okouma et al. 2011	147623
Formation compressibility (c_f)	5×10^{-6} psi ⁻¹	Wilson 2015	175029
Specific gas gravity	0.6	Okouma et al. 2011	147623
Typical perforation length	4 ft	Pope et al. 2009	125079

Table 8: Haynesville Shale parameters chosen for simulations and based on literature review

Parameter or input	Value
Depth interval (based on height and depth)	11,385 ft to 11,581 ft (3470m to 3530m)
Porosity	0.1
Formation compressibility	$5 \times 10^{-6} \text{ psi}^{-1}$ ($72.519 \times 10^{-6} \text{ bar}^{-1}$)
Typical perforation length	4 ft (1.22m) A perforation length of 3.3 ft (1m) was used in simulations.
Initial pressure	10,008 psia at a depth of 12,106 ft. (690 bar at a depth of 3690m)
Reservoir temperature	350 °F (177 °C)

The low permeability of unconventional reservoirs leads to rapid pressure changes near the wellbore (Roadifer and Kalaei, 2015). Therefore, accurate values for formation compressibility and porosity are required. Perforation length is also influential since grid blocks containing perforations can be expected to experience the most rapid pressure decreases.

3.3.2 Defaults included in software products

For simulations performed during this work, a dry gas pre-set fluid model included in Schlumberger Petrel was used. Relative permeabilities of gas and water were obtained from the shaly sand pre-set values in Schlumberger Petrel. Whilst data collected from rock and fluid samples taken from the Haynesville Shale may have been more accurate, it could be argued that it is beneficial to develop reservoir models for which subsequent users require data that is widely available.

4 Methods

4.1 Overview

In this work, two numerical shale gas reservoir models are assessed. The first is Kostyleva's (2019) model and the second is a new Multiple Fracture Zone (MFZ) model. Both aim to simulate the behaviour of shale gas reservoirs without specifically representing all of the complex processes that occur within them. Instead, both use simplified representations of the reservoir that describe the overall effects of the processes thought to be most influential. No effort is made to model geomechanics or individual fractures. This results in a far lower computer time requirement and far fewer unknown parameters.

4.2 Description and application of models studied

4.2.1 Common components

Both models use the idea of a repetitive element to further reduce the computer time requirement. Each perforation cluster along a horizontal wellbore and the reservoir surrounding it is represented by a repetitive model element. The lateral limits of each repetitive element recreate the effects of no flow boundaries assumed to exist halfway between wells and halfway between perforation intervals as a consequence of their simultaneous productivity. The upper and lower limits of each repetitive element represent the upper and lower limits of the reservoir. Equal production of gas from each repetitive element is assumed, as is equal BHP at all clusters.

Both models were built using Schlumberger Petrel and Eclipse. Table 9 gives the grid and well properties used. A dry gas pre-set fluid model included in Schlumberger Petrel was adapted for use in simulations and the adjustments made to it are given in tables 10 - 11. Fig. 8 shows the relative permeabilities of gas and water obtained from the shaly sand pre-set values in Schlumberger Petrel.

Table 9: Grid and well properties used for simulations.

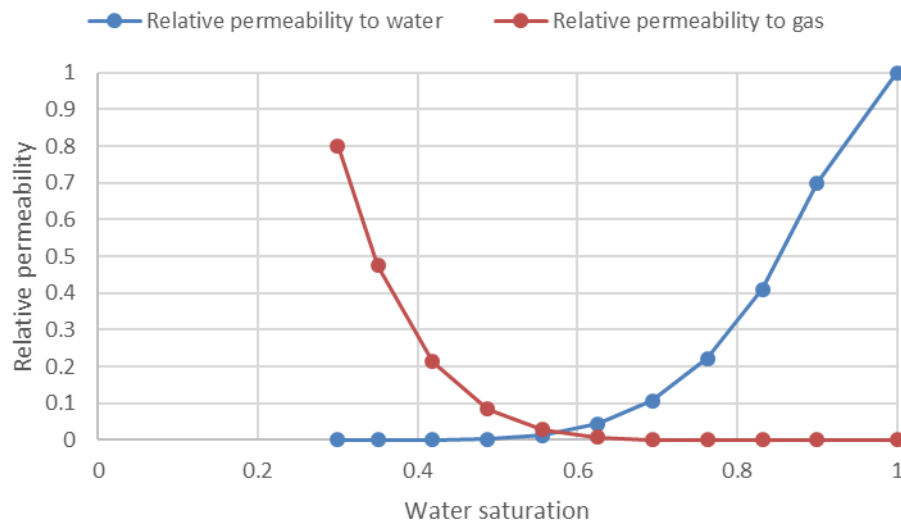
Parameter or input	Value(s) or description	Notes
Depth interval	11385 ft to 11581 ft (3470m to 3530m)	A 210ft (64m) reservoir thickness was used for grid refinement and aspect ratio studies of Kostyleva's (2019) model to allow greater flexibility in grid block dimensions.
Model repetitive element length	1000 ft (300 m)	Well spacing provided with completion data and identical for all wells. The width of repetitive elements varies between wells and is equal to the cluster spacing of the well.
Porosity	0.1	
Formation compressibility	$5 \times 10^{-6} \text{ psi}^{-1}$ ($72.519 \times 10^{-6} \text{ bar}^{-1}$)	
Well completion	Perforation extending for 3.3 ft (1 m) in centre of element.	Horizontal part of wellbore at depth of 11,483 ft (3500 m).

Table 10: Adjustments made to pre-set dry gas fluid model used in simulations.

Phases present	Gas, water
Reservoir temperature	350 °F (177 °C)
Gas gravity	0.584
Initial pressure	10,008 psia at a depth of 12,106 ft. (690 bar at a depth of 3690m)
Water contact	13,123 ft. (4000 m) Chosen so that all of model is above gas water contact.
Capillary pressure at water contact	0 psia (0 bar)

Table 11: Gas composition provided by gas analysis and entered to adjust fluid model.

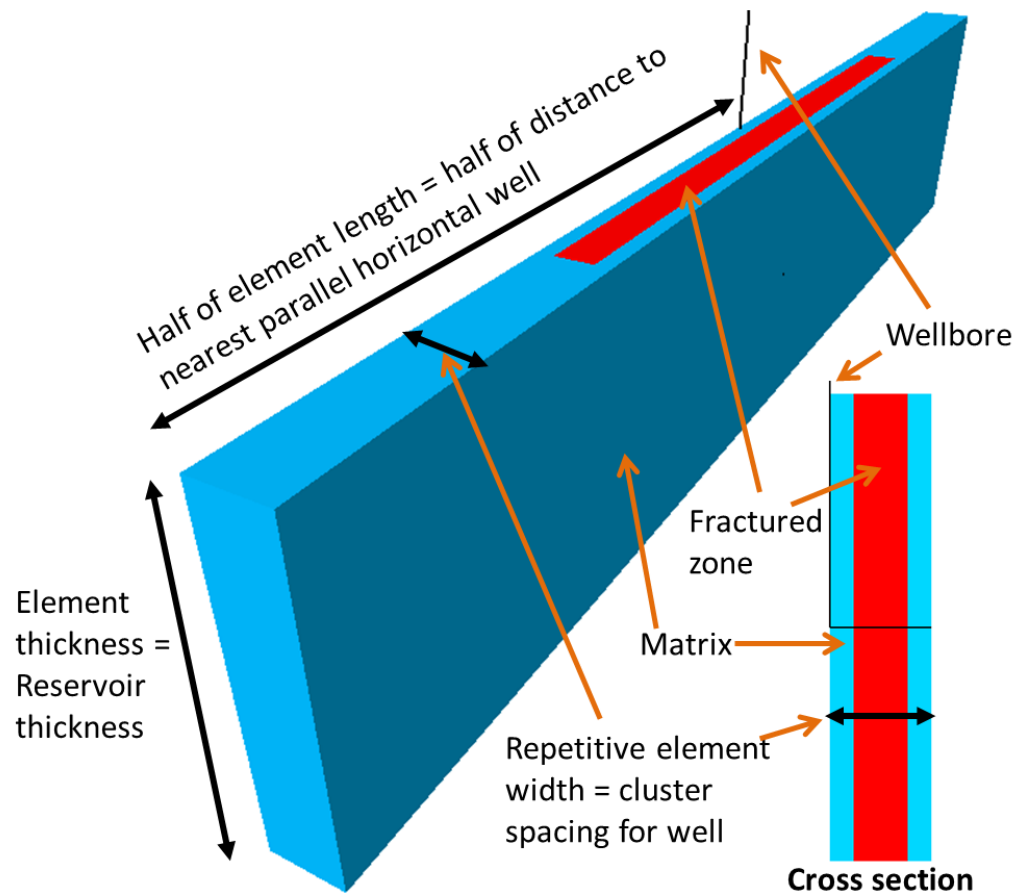
Component	Mole fraction
Methane	0.968757
Ethane	0.002821
Propane	0.000129
Iso-butane	0.000015
Normal-butane	0.00002
Nitrogen	0.000757
Carbon dioxide	0.027481
Hydrogen sulphide	0.00002

Figure 8: Relative permeabilities of gas and water used in simulations.

4.2.2 Kostyleva's (2019) model

Kostyleva's (2019) model consists of two reservoir regions with different initial permeabilities and different pressure-permeability functions. In Fig. 9, the enhanced permeability region representing the network of fractures (the fractured zone) created by stimulation is shown in red and the surrounding matrix region (the matrix zone) is shown in blue.

Figure 9: Single repetitive element of Kostyleva's (2019) model. Enhanced permeability region representing fracture network around horizontal wellbore shown in red. Surrounding matrix region shown in blue. The black line represents the wellbore.



The pressure-permeability functions are used to update the permeability at each point in the reservoir as the pressure field changes during production.

The permeability of the matrix zone starts to decline soon as the pore pressure of the matrix begins to fall. The permeability of the fractured zone only starts to decline after the pressure within it has fallen by a certain amount. Later on during a simulation, a pseudo-skin factor for the well is introduced and increases, from zero, with time.

Therefore, to history match data from a given well, the following parameters are varied.

1. Fractured zone dimensions.
2. Fractured zone initial permeability.
3. Fractured zone $k_f(p)$ function, including the pore pressure at which the fractured region permeability starts to decline.
4. Matrix region initial permeability.
5. Matrix region $k_m(p)$ function. The decline in the permeability of a grid block in the matrix zone begins as soon as the pore pressure within it falls beneath the initial reservoir pressure.
6. Onset of skin factor increase from zero.
7. Trend of skin factor increase with time.

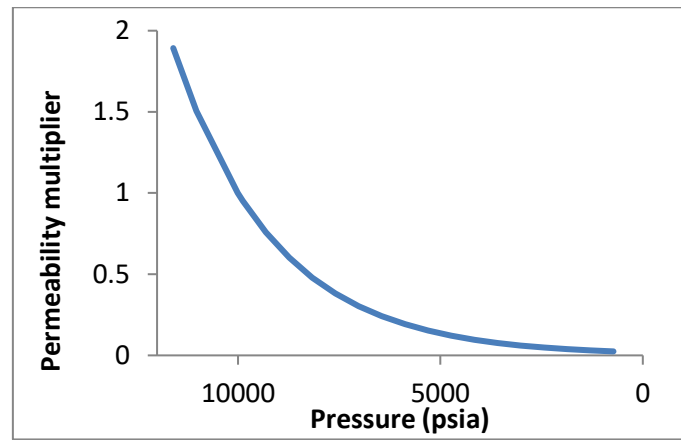
The $k(p)$ functions were entered to the simulator as tables of permeability multipliers applied to grid blocks depending on the pore pressure within them at each time step.

In this work, a matrix region $k_m(p)$ function obtained from core measurements was available. Therefore, it was used for all simulations using Kostyleva's (2019) model. It is given by equation 6 and shown in Fig. 10.

An example simulator input of Kostyleva's (2019) model is provided in the appendix.

$$\frac{k}{k_i} = e^{-0.0004(p_i - p)} \quad (6)$$

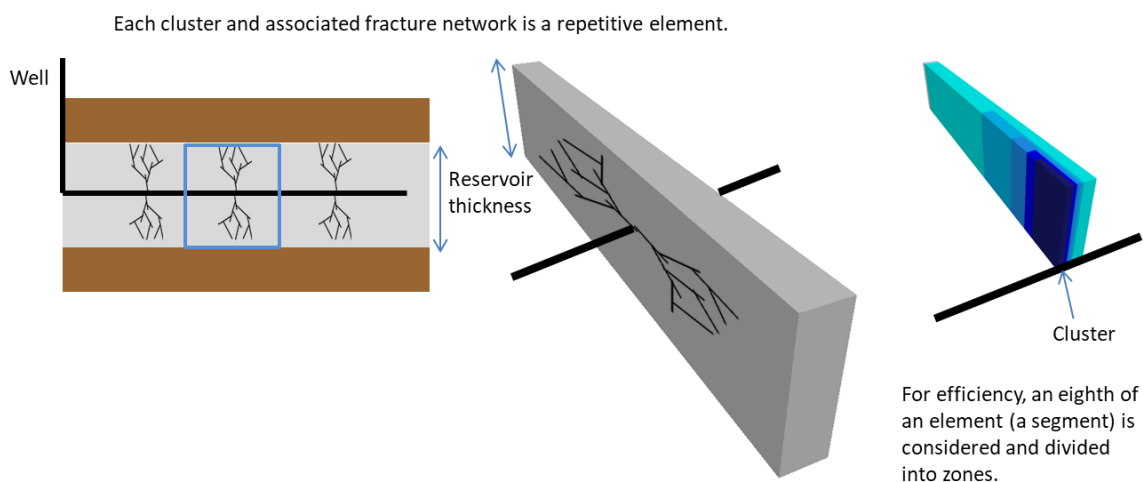
Figure 10: Permeability multipliers applied to matrix region grid blocks depending on their pore pressures at each time step during the simulation of all wells.



4.2.3 Multiple Fracture Zone (MFZ) model

In this new model, the repetitive element is divided into multiple zones in a manner that preserves its symmetry. In an effort to further reduce the computer time required, only one 8th of the element (referred to as a segment) is considered in simulations (Fig. 11). Equal production of gas from each segment is assumed. The cluster is at the centre of the element and therefore at the corner of the segment. Provided fluid pressure gradients from the top to the bottom of the element are not excessive, fluid flow towards and pressure field evolution around the cluster should be roughly symmetrical in all directions.

Figure 11: A repetitive element of the multiple fracture zone model and a segment of it.



The number of zones and their dimensions (referred to as the zone map) can vary between reservoirs. Therefore, before the model is applied to a given reservoir, a preliminary study must be conducted to find a zone map which allows accurate history matching to a well from it. The size of a segment can vary between wells depending on cluster and well spacing. Therefore, a portion of the zone map is discarded for some wells and the extent of the outermost zone is increased for other wells. The model only considers the region of the reservoir that contributes to production. Therefore, each zone represents a volume of shale containing both matrix and fractures.

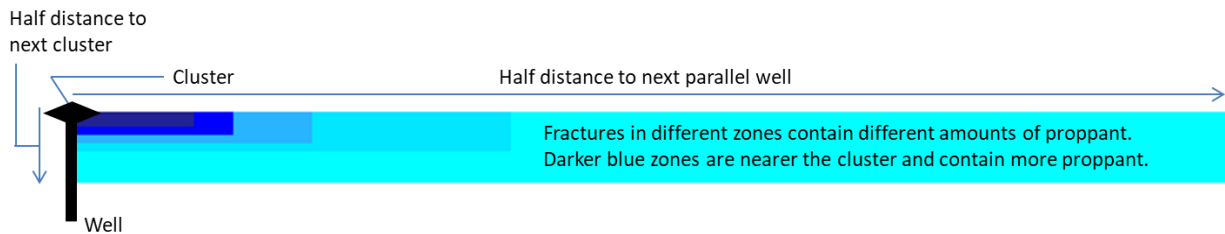
As reservoir pressure falls, the effective stress in a formation increases (Okouma *et al.*, 2011). If it is assumed that only horizontal stress acts to close fractures and that the contribution of the matrix to shale permeability is insignificant compared to that of the fractures, equations 7 and 8 give the permeability of a volume of shale containing fractures as reservoir pressure falls (Chen D. *et al.*, 2015).

$$k = k_i e^{3c_{fracture} \frac{v}{1-v} \alpha_b (p - p_i)} \quad (7)$$

$$c_{fracture} = -\frac{1}{\varphi_f} \frac{\partial \varphi_f}{\partial \sigma_e} \quad (8)$$

If the Poisson's ratio, Biot coefficient and initial pressure are known for a reservoir, only the initial permeability and fracture compressibility must be determined. The Poisson's ratio and Biot coefficient for the Haynesville shale are assumed to be 0.2 and 1 respectively as in work by Wilson (2015). In the MFZ model, each zone represents a region of the reservoir in which the fractures contain a different proppant concentration. Fractures in zones nearer the wellbore are likely to contain more proppant (Xu *et al.*, 2010). Since more proppant reduces the effect of closure stress on a fracture, fractures in zones nearer the wellbore will have a lower compressibility than those in zones further away from the wellbore. Therefore, in the MFZ model, equation 7 is applied to all zones but with a different fracture compressibility for each zone. All zones are assumed to have the same initial permeability. Fig. 12 shows an example zone map. Fractures in different zones contain different amounts of proppant. Darker blue zones are nearer the cluster and contain more proppant. The zones are numbered with the innermost zone, nearest the cluster, referred to as zone 1. The outermost zone in figure 12 would be referred to as zone 5.

Figure 12: A segment viewed from above to show an example zone map.



An iterative approach is used to vary the parameters listed below to match observed data.

1. Initial reservoir permeability. This value is used for all zones.
2. Fracture compressibility. A different value is used for each zone. Equation 7 shows that this, in combination with the Poisson's ratio and Biot coefficient for the reservoir, results in a permeability multiplier which is a function of pressure for each zone.
3. Initial reservoir pressure. This is used in equation 7.
4. Reservoir pressure at start of production. For a given well, this can be less than the initial reservoir pressure.

An example simulator input of the MFZ model is provided in the appendix.

4.3 Tests performed to assess each model

A number of tests were performed to assess each model. The details of these are given below. Their results are described and discussed in the next chapter.

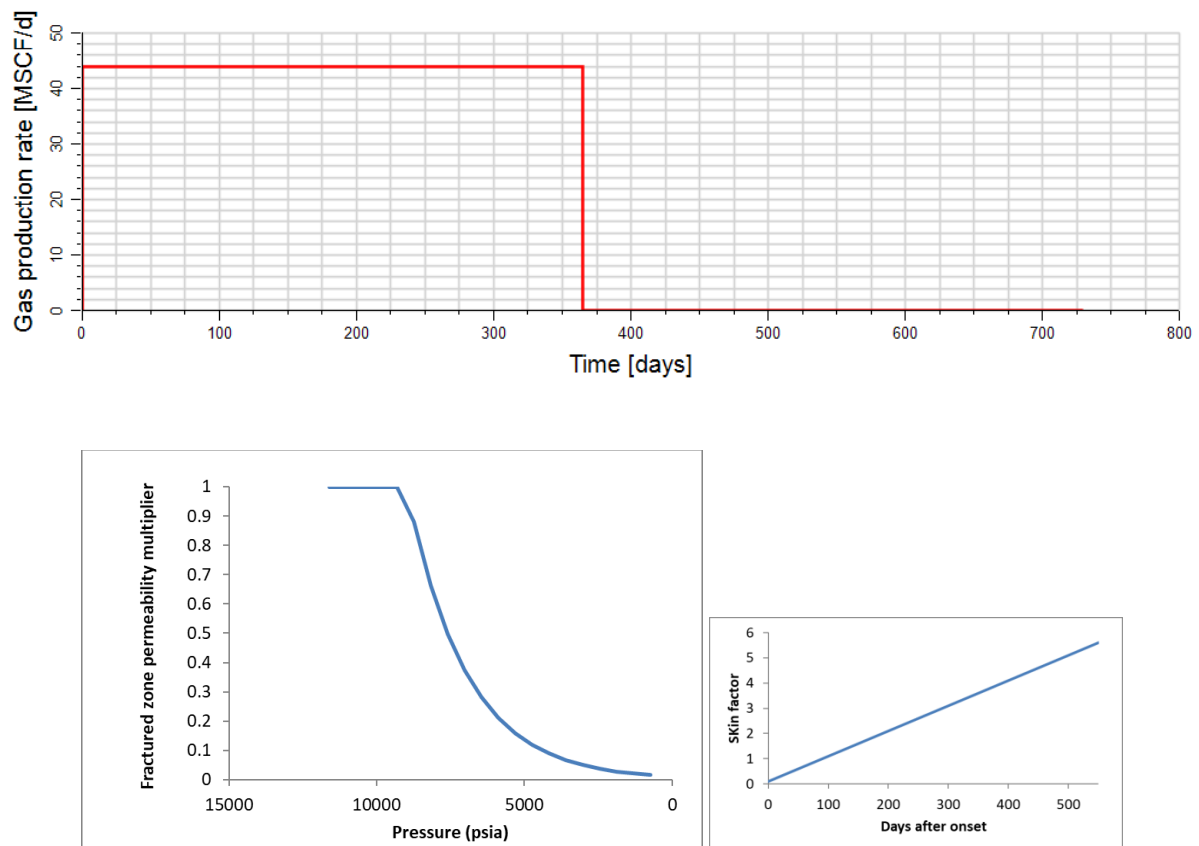
4.3.1 Kostyleva's (2019) model

4.3.1.1 Grid refinement study

The arbitrary reservoir and production data given in table 12 and figure 13 were entered into two versions of Kostyleva's (2019) model. The values were chosen for their similarity to data from real wells. Each version of the model used a grid with cubic grid blocks. The length of the side of the blocks was varied between versions as described in table 13. The resulting bottomhole pressure trends were compared to determine the optimum grid block size given the increased computational demands of using smaller, and therefore more, grid blocks.

Table 12: Reservoir data used in grid refinement study of Kostyleva's (2019) model.

Reservoir thickness	210ft (64m)
Repetitive element width	52ft (16m)
Repetitive element length	984ft (300m)
Fractured zone width	26ft (8m)
Fractured zone length	394ft (120m)
Matrix zone initial permeability	0.002mD
Fractured zone initial permeability	0.1mD
Onset of skin factor increase from zero	After 150 days production

Figure 13: Reservoir and production data used for grid refinement study of Kostyleva's (2019) model.**Table 13: Grid block side lengths used in grid refinement study of Kostyleva's (2019) model.**

Grid block side length	Total number of grid blocks
6.6ft (2m)	38,400
13.1ft (4m)	4,800

4.3.1.2 Aspect ratio study

For the wells studied in this research, the well spacing far exceeds the cluster spacing and reservoir thickness. Therefore, in the repetitive elements of Kostyleva's (2019) model, if cubic grid blocks are used, the horizontal direction perpendicular to the horizontal wellbore contributes far more to the number of grid blocks than any other. A number of simulations were performed in which the length of the grid blocks was varied in only this direction. The other sides of the grid blocks were kept at the 13.1ft (4m) length found to give almost identical results as a finer grid. Table 14 describes the grids used. The arbitrary reservoir and production data used are given in table 15 and figure 14.

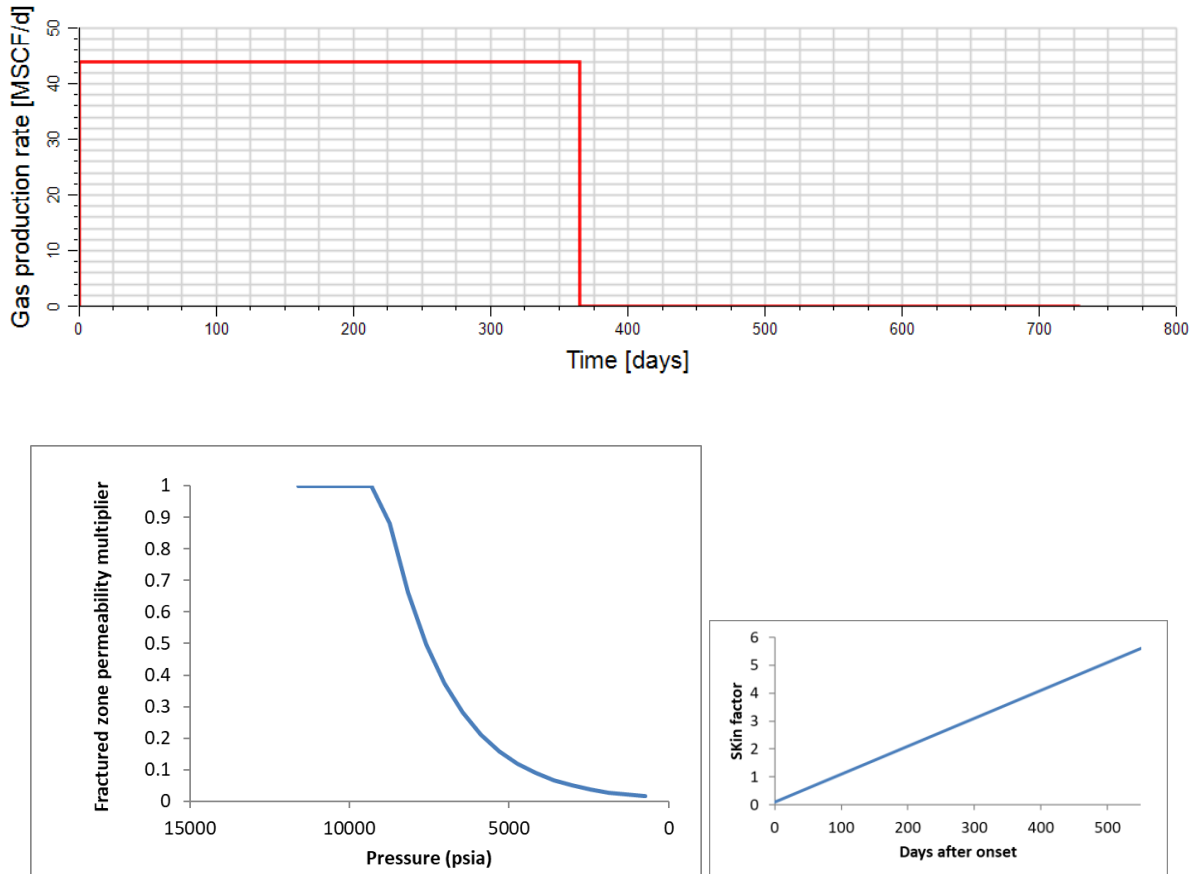
Table 14: Grids used in aspect ratio study of Kosyleva's (2019) model.

Longest grid block side length (horizontal direction perpendicular to wellbore)	Length of other grid block sides	Total number of grid blocks
13.1ft (4m)	13.1ft (4m)	4 x 75 x 16 = 4800
32.8ft (10m)		4 x 30 x 16 = 1920
65.6ft (20m)		4 x 15 x 16 = 960

Table 15: Reservoir data used in aspect ratio study of Kostyleva's (2019) model.

Reservoir thickness	210ft (64m)
Repetitive element width	52ft (16m)
Repetitive element length	984ft (300m)
Fractured zone width	26ft (8m)
Fractured zone length	394ft (100m)
Matrix zone initial permeability	0.002mD
Fractured zone initial permeability	0.1mD
Onset of skin factor increase from zero	After 150 days production

Figure 14: Reservoir and production data used for aspect ratio study of Kostyleva's (2019) model.



4.3.1.3 Effect of timestep duration

The effect of solution timestep duration on simulation results was studied. Four simulations were performed, each with a different maximum timestep duration. These were 0.1 days, 1 day, 5 days and 10 days. A grid comprising cubic blocks of 13.1ft (4m) length was used based on the findings of the grid refinement and aspect ratio studies. The reservoir and production data entered was the same as that used for the aspect ratio study.

4.3.1.4 Effect of well inflow equation

The effect of the method used to model flow from grid blocks into the wellbore was studied. One simulation was performed using the standard method for the simulation software which does not take account of the pressure dependence of the gas mobility. One simulation was performed using pseudo-pressure to take account of it. Following the findings of the relevant studies, a grid comprising cubic blocks of 13.1ft (4m) length was used and the maximum allowable solution timestep duration was 5 days. The reservoir and production data entered was the same as that used for the aspect ratio study.

4.3.1.5 History matching

To validate Kostyleva's (2019) model, it was history matched, under rate control, to the 2014 – 2016 Haynesville Shale dataset. An iterative process was used and table 16 describes the ranges considered acceptable for input parameters with a single value and contains comments on why this was so.

Table 16: Ranges of input parameters used for history matching to Kostyleva's (2019) model.

Parameter	Acceptable range	Comments
Matrix zone initial permeability	Up to 0.01 md	Based on values published by Wilson (2015) and Okouma et al. (2011).
Fractured zone initial permeability	Must be greater than that of the matrix zone and not exceed 1 md.	Based on Kostyleva's (2019) work.
Fractured zone width	10 – 25 ft (3 – 8 m)	
Fractured zone length	100 – 1400 ft (30 - 428 m)	
Difference between initial reservoir pressure and BHP at skin onset	Greater than 6000 psia (414 bar).	
Repetitive element dimensions	Not applicable	Determined by well and cluster spacing.

4.3.1.6 Prediction

Once the parameters of Kostyleva's (2019) model have been found by history matching for a given well, the pressure trend that would occur for any subsequent production schedule can be simulated. This could be described as the use of the model to predict BHP. To assess the usefulness of the model for this purpose, it was history matched to the 2014 – 2018 Haynesville Shale dataset for the shortest initial period necessary to obtain a set of model parameters which then allowed accurate simulation of the rest of the dataset. This was done for wells E and F because their datasets covered more time than those of other wells.

4.3.1.7 Sensitivity

For both history matching and prediction, the model is defined by a number of parameters and then simulates the BHP trend under rate control. The effect of changes in these parameters on this trend was studied. A successful history match to well E was used as the base case. For each parameter, a set of simulations was run in which it was varied but all other parameters remained the same as for the base case.

4.3.2 Multiple Fracture Zone (MFZ) model

4.3.2.1 Selection of zone map

A preliminary study was conducted to find the minimum number of zones needed to history match one well and their dimensions so that this zone map could be used for subsequent simulations. Fewer zones results in fewer unknown parameters when the model is used for history matching because each zone has a different fracture compressibility. The 2014 – 2018 dataset from well E was chosen because of its longer duration than other datasets. Given the need for flexibility in zone dimensions and the findings of the grid refinement and aspect ratio studies of Kostyleva's (2019) model, cubic grid blocks of length 1.64ft (0.5m) were used. Following the results of other studies of Kostyleva's (2019) model, a maximum timestep of 10 days was used and pseudo – pressure was not used to model the flow of gas into the wellbore.

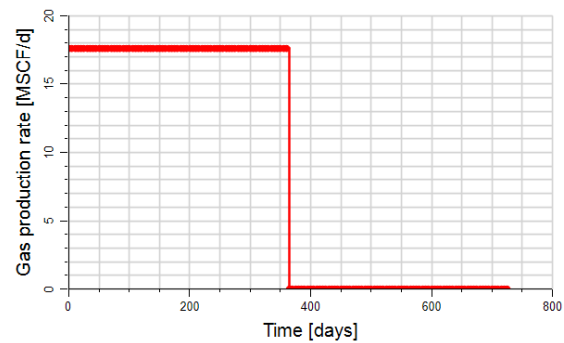
4.3.2.2 Grid refinement study

The arbitrary reservoir and production data given in figure 15 were entered into two versions of the MFZ model. The values were chosen for their similarity to data from real wells and following the results of the previously described studies of Kostyleva's (2019) model. Each version of the model used a grid with cubic grid blocks. For one, the length of the blocks was 3.28ft (1m), for the other it was 1.64ft (0.5m). The five zone map selected in the preceding study was used. The resulting bottomhole pressure trends were compared to determine the optimum grid block size given the increased computational demands of using smaller, and therefore more, grid blocks.

Figure 15: Input data used for grid refinement study of MFZ model.

Segment thickness (ft)	98.4
Segment width (ft)	26.2
Segment length (ft)	492
Initial reservoir permeability (mD)	0.15
Initial reservoir pressure (psia)	10,008
Reservoir pressure at start of production (psia)	10,008
Maximum timestep duration (days)	5

Zone	Fracture compressibility (1/psia)
1	0.00013
2	0.00040
3	0.00107
4	0.00147
5	0.00227



4.3.2.3 Aspect ratio study

For the wells studied in this research, the well spacing far exceeds the cluster spacing and reservoir thickness. Therefore, in the segments of the MFZ model, if cubic grid blocks are used, the horizontal direction perpendicular to the horizontal wellbore contributes far more to the number of grid blocks than any other. A number of simulations were performed in which the length of the grid blocks was

varied in only this direction. The other sides of the grid blocks were kept at the 3.28ft (1m) length found to give similar results as a finer grid. The input data was the same as that used for the grid refinement study.

4.3.2.4 Effect of timestep duration

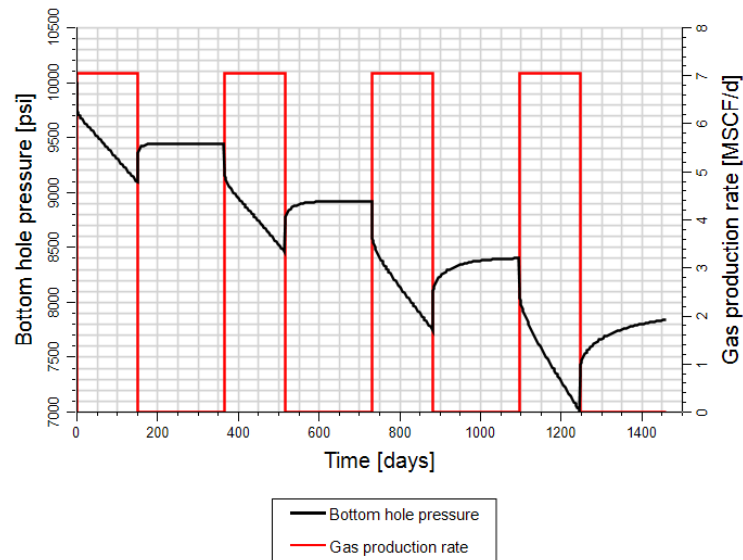
The effect of solution timestep duration on simulation results was studied. Four simulations were performed, each with a different maximum timestep duration. These were 0.1 days, 1 day, 5 days and 10 days. A grid comprising cubic blocks of 3.28ft (1m) length was used based on the findings of the grid refinement and aspect ratio studies. The input data was the same as that used for those studies.

4.3.2.5 Effect of well inflow equation

The effect of the method used to model flow from grid blocks into the wellbore was studied. One simulation was performed using the standard method for the simulation software which does not take account of the pressure dependence of the gas mobility. Another simulation was performed using pseudo-pressure to take account of it. Following the findings of the preceding studies, a grid comprising cubic blocks of 3.28ft (1m) length was used and the maximum allowable solution timestep duration was 1 day. The other input data was the same as for the preceding studies.

4.3.2.6 Pressure transient analysis

To assess the pressure transient signature of the MFZ model and how it is affected by depletion as production proceeds, a series of constant rate drawdowns and build ups was simulated (figure 16) using the findings of the previous studies and the same input data.

Figure 16: A series of drawdowns and build ups simulated using the MFZ model.

4.3.2.7 History matching

The 2014 – 2018 Haynesville Shale dataset was used to validate the MFZ model. For each of wells A - H, the production data was used as the input to the model and its parameters were varied in an effort to accurately simulate the BHP trend. Table 17 describes the ranges considered acceptable for input parameters with a single value.

Table 17: Ranges of input parameters used for history matching to MFZ model.

Parameter	Acceptable range	Comments
Initial permeability	Must not exceed 1 md	The model only considers regions of the reservoir affected by fracturing and therefore the same range is used as for the fractured zone in Kostyleva's (2019) model.
Fracture compressibility	Must be greater in zones further from the wellbore.	Zones further from the wellbore are expected to contain less proppant.

4.3.2.8 Prediction

Once the parameters of the model have been found by history matching for a given well, the pressure trend that would occur for any subsequent production schedule can be simulated. This could be described as the use of the model to predict BHP. To assess the usefulness of the model for this purpose, it was history matched to the 2014 – 2018 Haynesville Shale dataset for the shortest initial period necessary to obtain a set of model parameters which then allowed accurate simulation of the rest of the dataset. This was done for wells E and F because their datasets covered more time than those of other wells.

4.3.2.9 Sensitivity

For both history matching and prediction, the model is defined by a number of parameters and then simulates the BHP trend under rate control. The effect of changes in these parameters on this trend was studied. A successful history match to well E was used as the base case. For each parameter, a set of simulations was run in which it was varied by 20% but all other parameters remained the same as for the base case.

5 Results and discussion

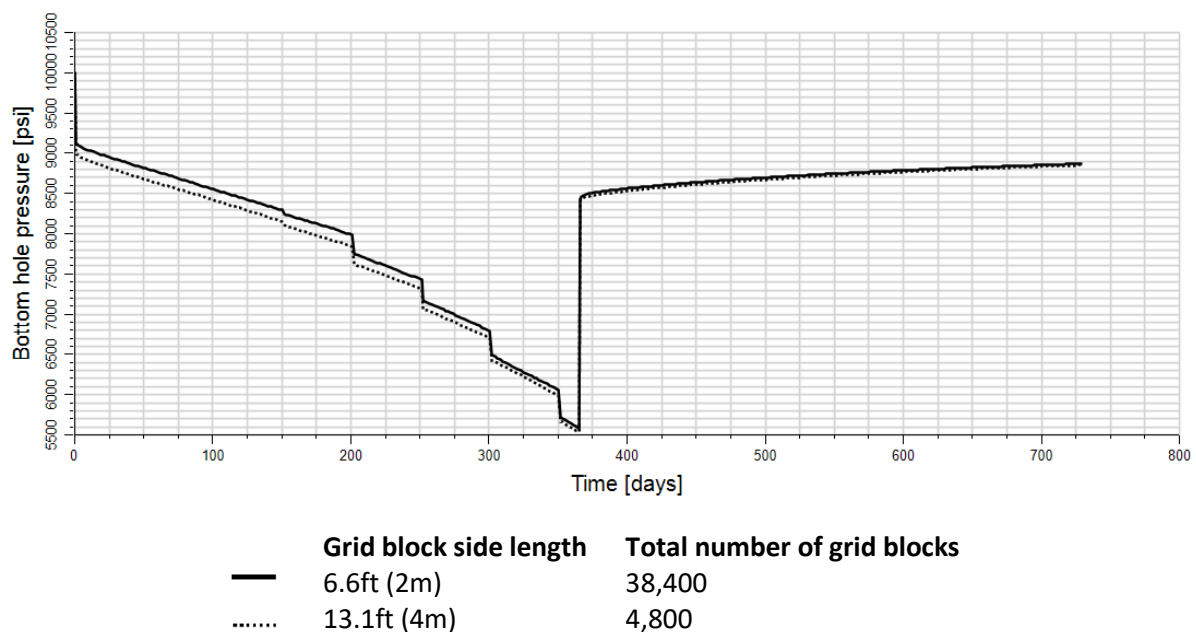
5.1 Kostyleva's (2019) model

5.1.1 Grid refinement study

Figure R1 shows the bottomhole pressure trends simulated using grids comprising cubic grid blocks of different lengths. There is little difference in the results obtained from the more and less coarse grids. Therefore, using the coarser 13.1ft (4m) grid blocks can reduce simulation time without significantly affecting the results obtained. However, whilst a coarser grid reduces simulation time, it also reduces the flexibility of the model during the history matching process. This is because each grid block must be assigned to either the fractured zone or the matrix zone so the dimensions of these zones can only be altered by increments equal to the length of one grid block.

The step pattern in the pressure trends results from increases in the pseudo skin factor. It should be noted that the pseudo skin factor continues to increase during the build up.

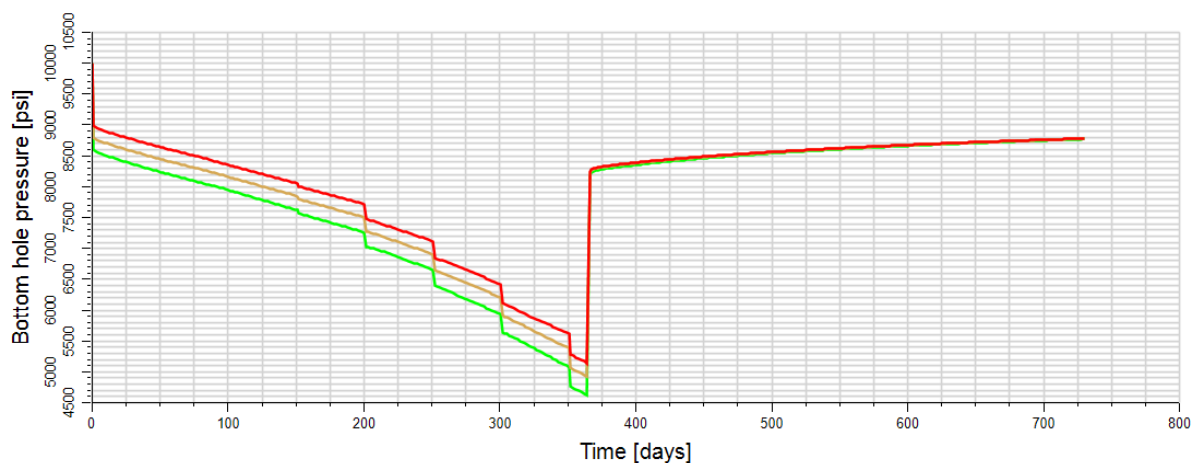
Figure R1: Bottomhole pressure trends simulated using Kostyleva's (2019) model with grids comprising blocks of different lengths.



5.1.2 Aspect ratio study

Figure R2 shows the bottomhole pressure trends simulated using grids containing blocks with different aspect ratios. During the drawdown, the use of different aspect ratios produces a noticeable and consistent effect on the simulated bottomhole pressure values. This is different to the effect of using a coarser grid which, as shown in figure R1, has an effect which diminishes as the drawdown proceeds. Therefore, the use of cubic grid blocks is recommended. Both grid refinement and aspect ratio alteration appear to have little effect on simulated build up pressures.

Figure R2: Bottomhole pressure trends simulated using Kostyleva's (2019) model with grids comprising blocks of different aspect ratios.

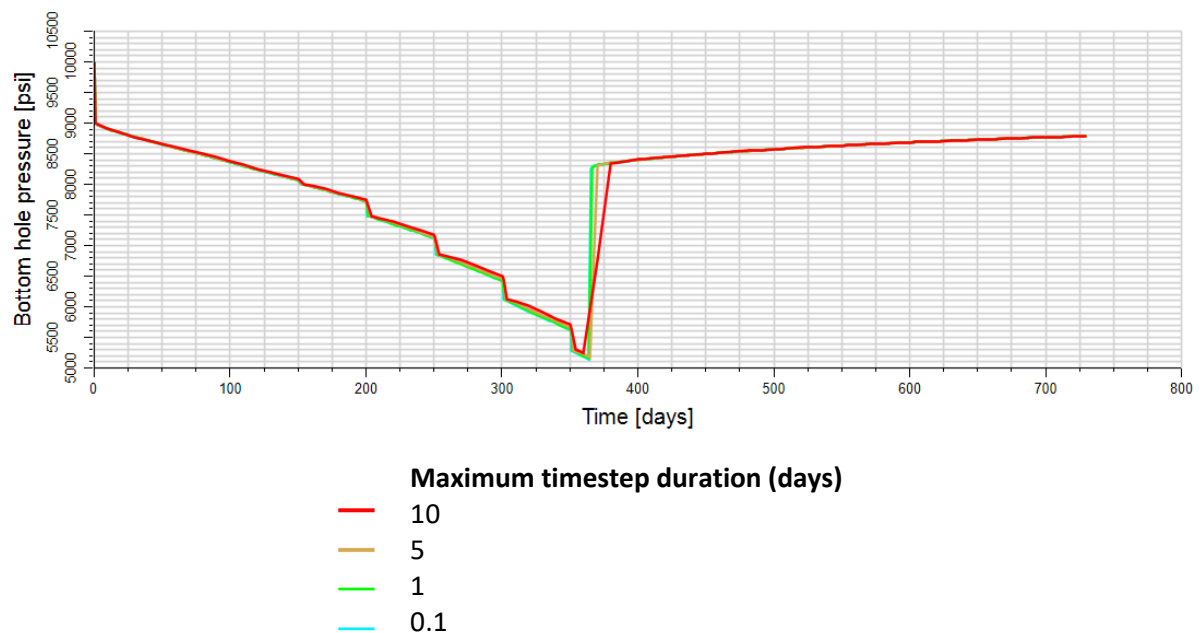


	Longest grid block side length (horizontal direction perpendicular to wellbore)	Length of other grid block sides	Total number of grid blocks
—	13.1ft (4m)		$4 \times 75 \times 16 = 4800$
—	32.8ft (10m)	13.1ft (4m)	$4 \times 30 \times 16 = 1920$
—	65.6ft (20m)		$4 \times 15 \times 16 = 960$

5.1.3 Effect of timestep duration

Figure R3 shows the bottomhole pressure trends simulated using different maximum allowable timesteps. Only slight differences are noticeable. Therefore, a maximum timestep duration of 10 days is acceptable.

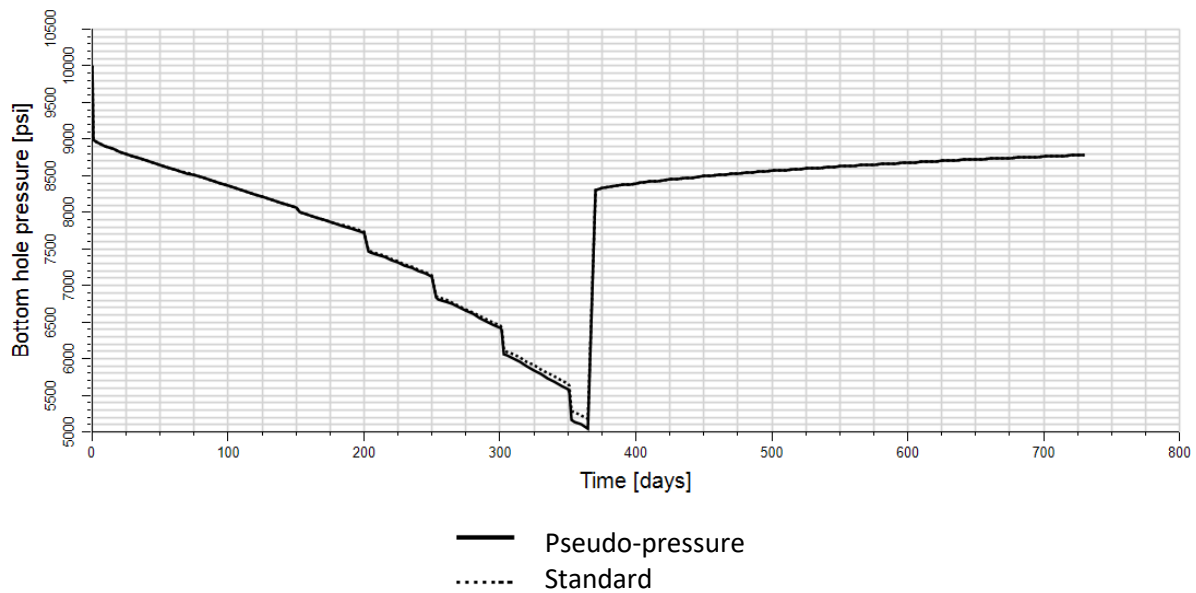
Figure R3: Bottomhole pressure trends simulated using Kostyleva's (2019) model with different maximum timestep durations.



5.1.4 Effect of well inflow equation

Figure R4 compares the bottomhole pressure trends simulated with and without the use of pseudo-pressure to account for the pressure dependence of gas mobility when modelling the flow of gas from grid blocks into the wellbore. Only slight differences are noticeable. These occur during the drawdown below pressures of around 6,000 psi (414 bar).

Figure R4: Bottomhole pressure trends simulated using Kostyleva's (2019) model with and without the use of pseudo-pressure to model the flow of gas from grid blocks into the wellbore.



5.1.5 History matching

5.1.5.1 Overview of results

Fig. R5 shows pressure history matches between observed and simulated data for the wells used in the continued validation of Kostyleva's (2019) model (wells A – H) and for one well (well Mc) used in the initial validation by Kostyleva (2019). The label “ $km(p)$, no $k_f(p)$ ” refers to a simulation with pressure-dependent permeability $k_m(p)$ in the matrix zone, constant permeability in the fractured zone, and no pseudo-skin effect. “ $km(p)$, $k_f(p)$ ” refers to a simulation with pressure-dependent permeabilities in both matrix, $k_m(p)$, and fractured, $k_f(p)$, zones, and no pseudo-skin effect. Simulations using $k_m(p)$, $k_f(p)$ and a pseudo-skin factor are labelled “*Skin*”. A pseudo-skin-dominated behaviour is yet to occur for wells A, B, C, D, G and H.

Fig. R5 also shows a plot of cumulative production vs. normalized gas production rate for each well. The onsets of the $k_f(p)$ function and the skin effect used to achieve a match for a given well coincide with changes in pseudo-linear trends (shown as red lines). The cumulative production vs. normalized gas production rate plots include data from all wells studied during the JIP.

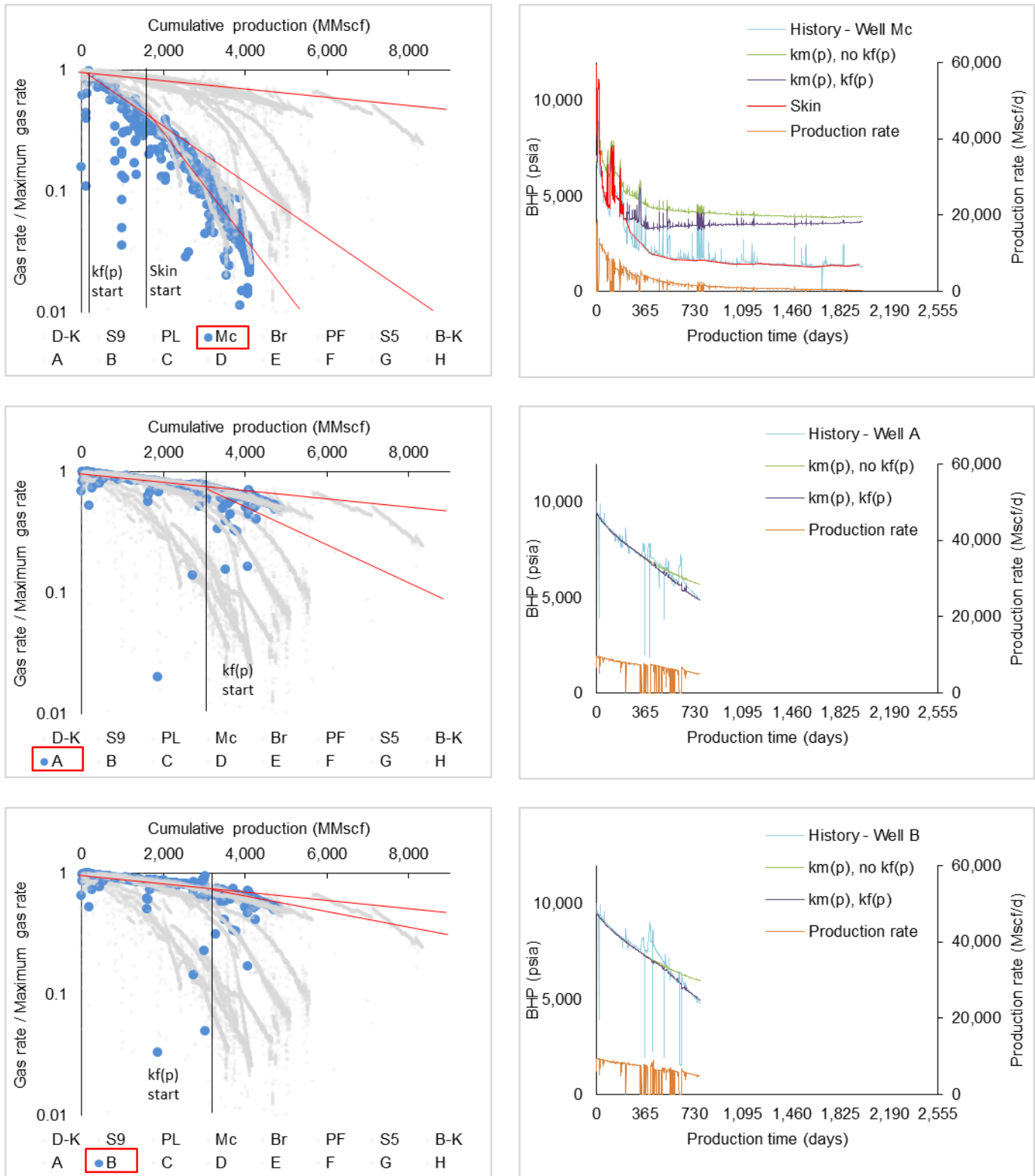
It is clear from Fig. R5 that simulations with pressure-dependent permeabilities in both matrix and fractured zones, and a pseudo-skin effect (where needed) provide good matches with observed data. This contributes to the validation of the model.

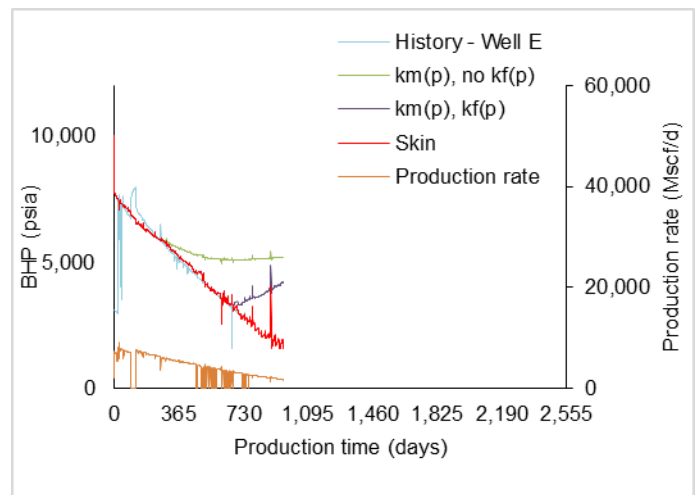
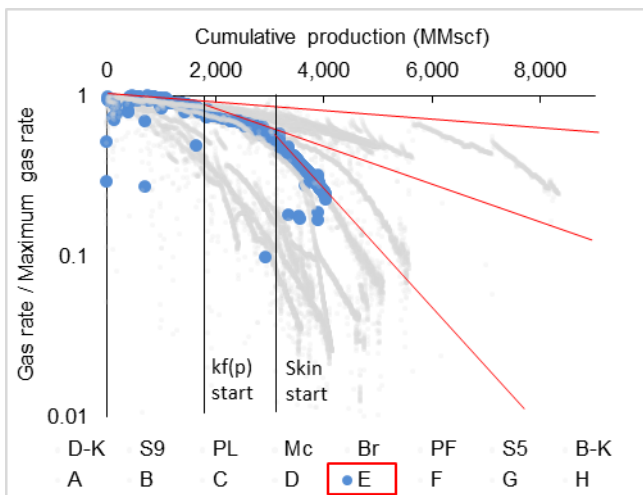
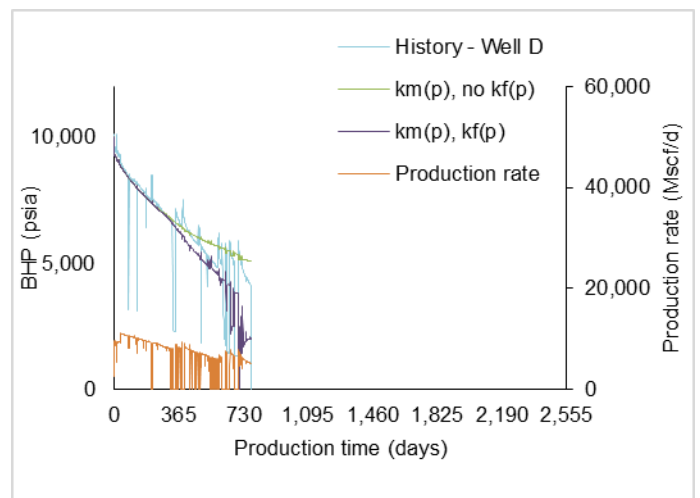
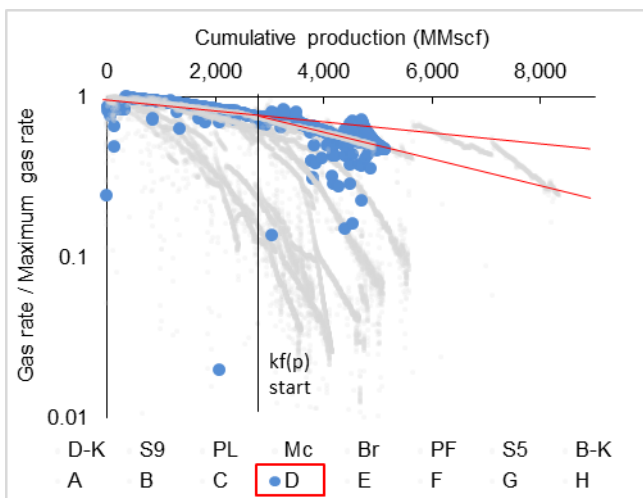
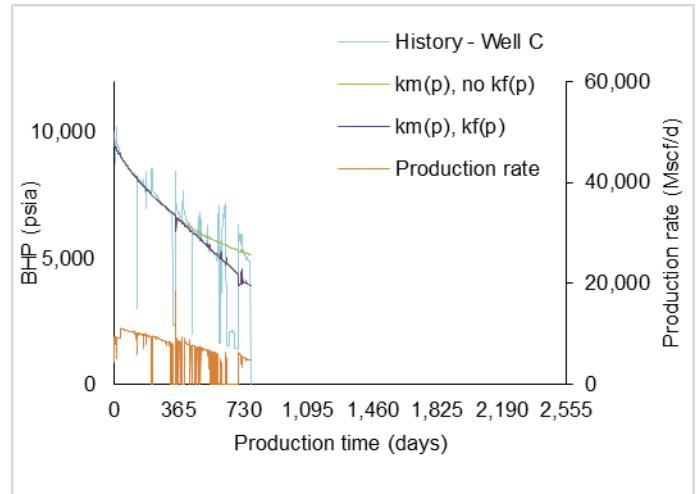
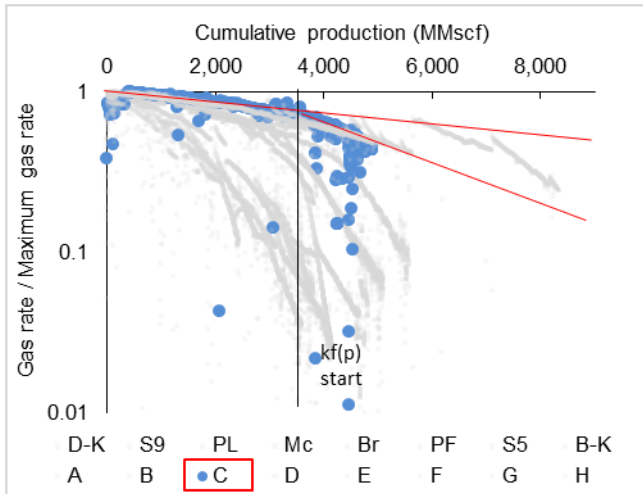
Table R1 and Figs R6, R7 and R8 summarise the model parameters used to obtain the matches shown in Fig. R5 as well as those used during the initial validation of the model by Kostyleva (2019). In Fig. R8, red lines are used to highlight successive linear relationships between pseudo-skin factors and time.

A grid comprising cubic blocks 3.28 ft (1m) in length was used. The findings of the grid refinement study suggest a coarser grid could have been used. However, since each block must be assigned to either the matrix or the fractured zone, a finer grid allowed greater flexibility in the dimensions of these.

Pseudo-pressure was not used to account for the pressure dependence of gas mobility when modelling the flow of gas from grid blocks into the wellbore as it made little difference to simulation results during the study of the effect of well inflow equation. However, a number of wells reached BHP values below the lowest for which the effect of well inflow equation was studied. For these, the use of pseudo-pressure may have been beneficial.

Figure R5: Left column – Cumulative production vs normalized gas rate plots with changes in trend highlighted using red lines and $k_f(p)$ /skin onsets marked using black lines. Right column – Comparisons between simulated BHP values predicted using different combinations of model components and observed (history) BHP (calculated from THP) values.





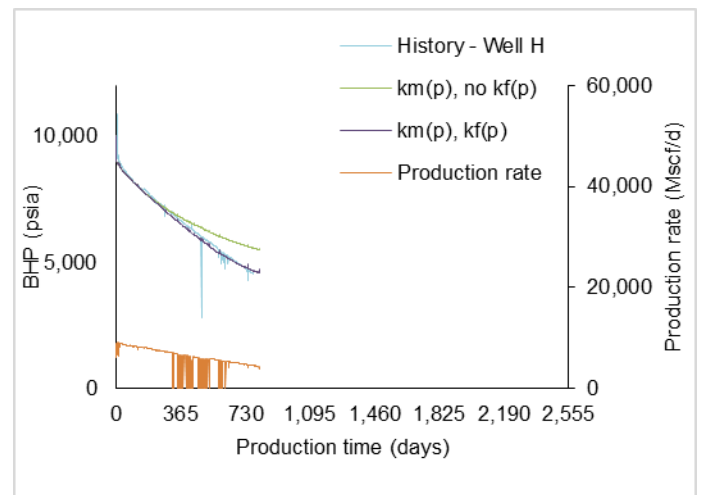
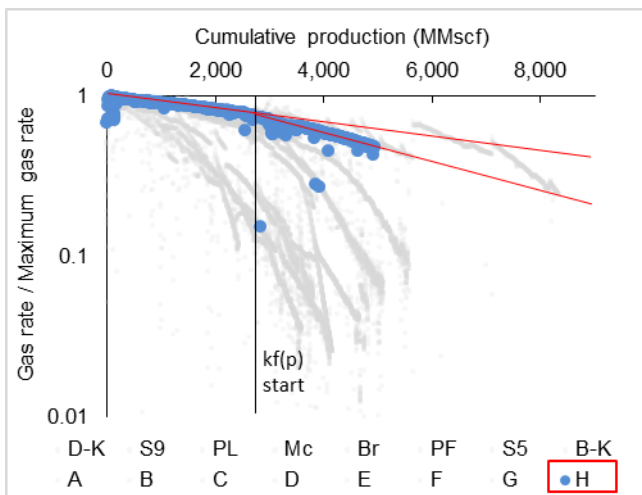
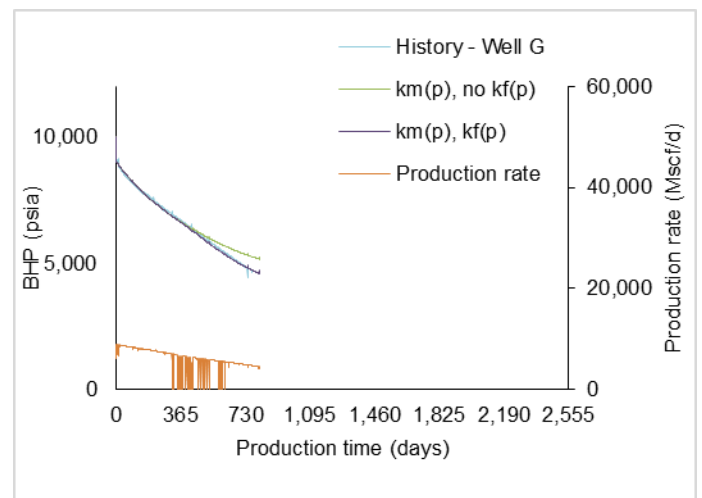
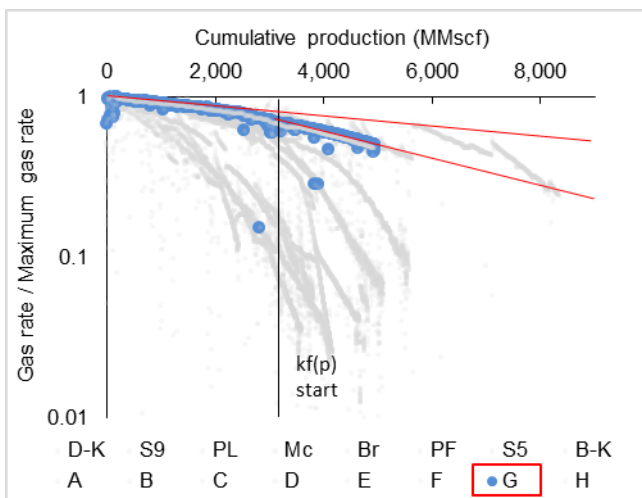
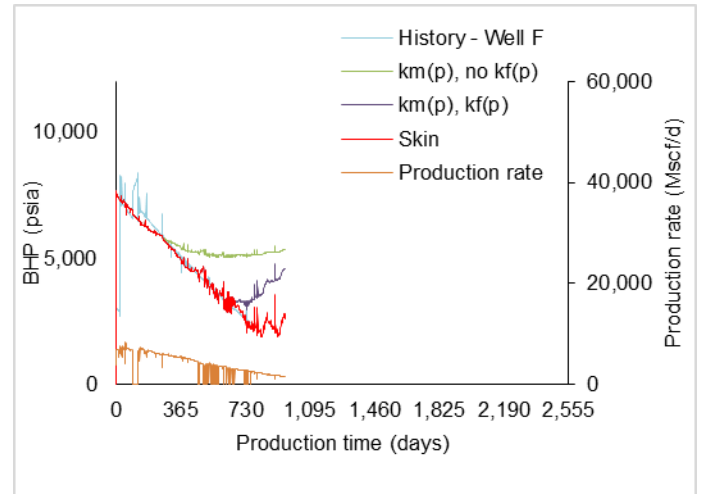
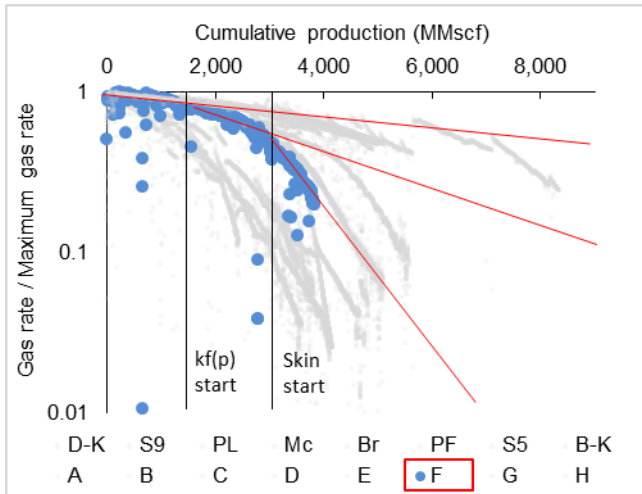


Table R1: Well completion data and model parameters used for history matching to Kostyleva's (2019) model.

Well	Completion		Fractured zone dimensions		Initial permeability (md)		Difference between initial reservoir pressure and BHP at skin onset (psia). (If skin effect reached)
	Cluster spacing (ft)	Proppant (lbs/ft lateral length)	Width (ft)	Length (ft)	Matrix zone	Fractured zone	
A	36	2000	16	407	0.0035	0.25	
B	36	2000	16	446	0.0038	0.29	
C	36	2000	16	427	0.0027	0.335	
D	36	2000	16	407	0.0035	0.25	
E	56	1200	23	427	0.0014	0.095	6730
F	56	1200	23	427	0.0012	0.085	6962
G	43	2500	23	525	0.0022	0.188	
H	56	2500	23	459	0.004	0.22	
Mc	79		17	166	0.0002	0.007	6896

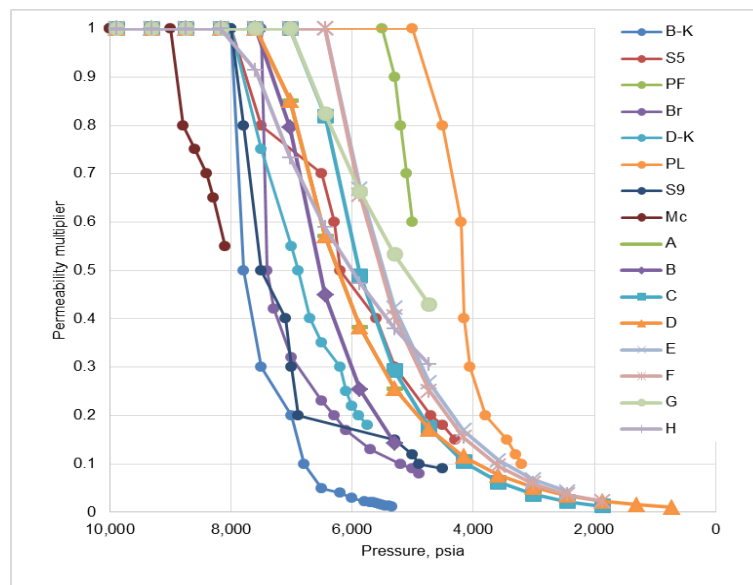
Figure R6: $K_r(p)$ functions used to simulate validation wells in this work (A – H) and during initial model validation by Kostyleva (2019).

Figure R7: Normalized $k_f(p)$ functions used to simulate validation wells in this work (A – H) and during initial model validation by Kostyleva (2019). The $k_m(p)$ function used for all wells is also shown.

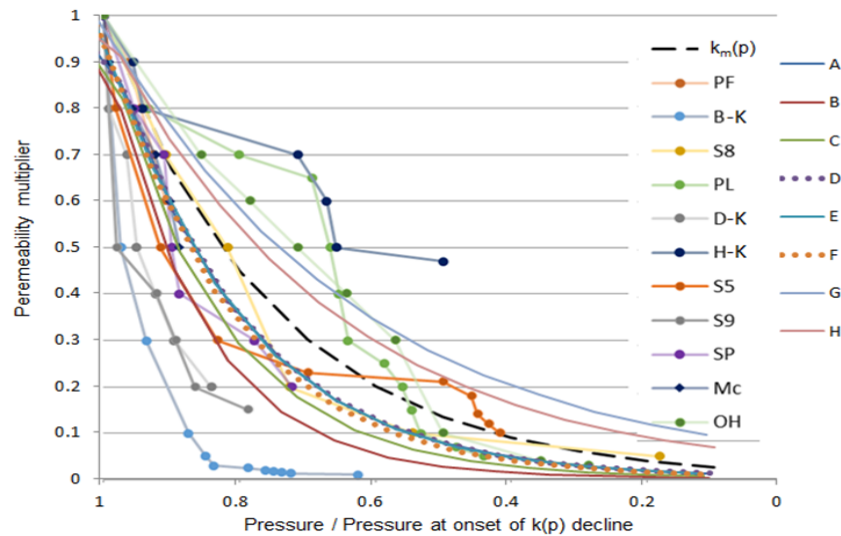
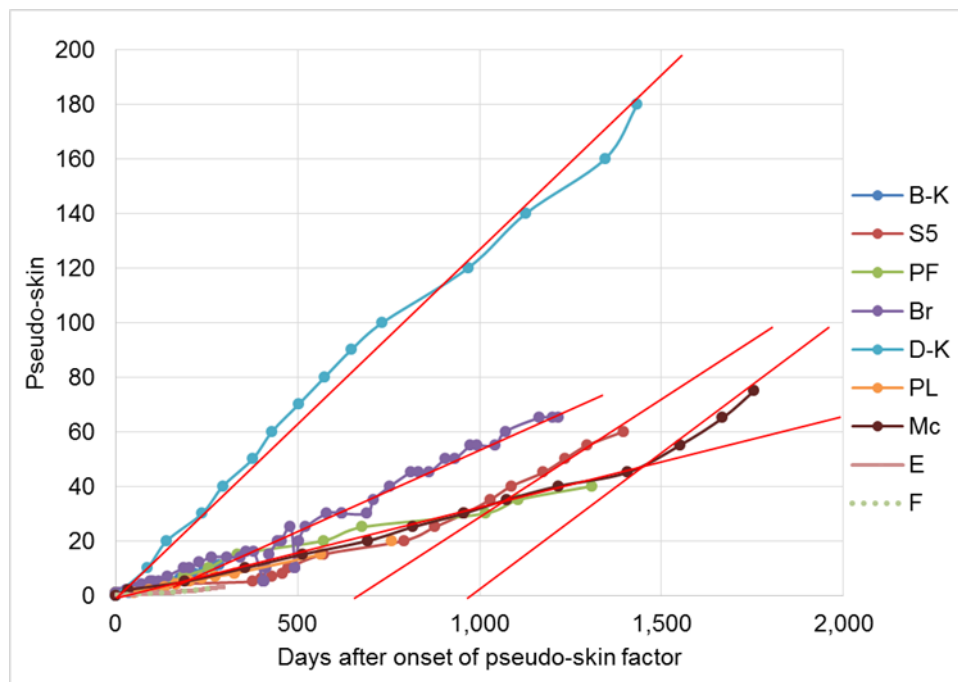


Figure R8: Pseudo-skin factors used to simulate validation wells in this work (E and F) and other wells studied in the JIP.



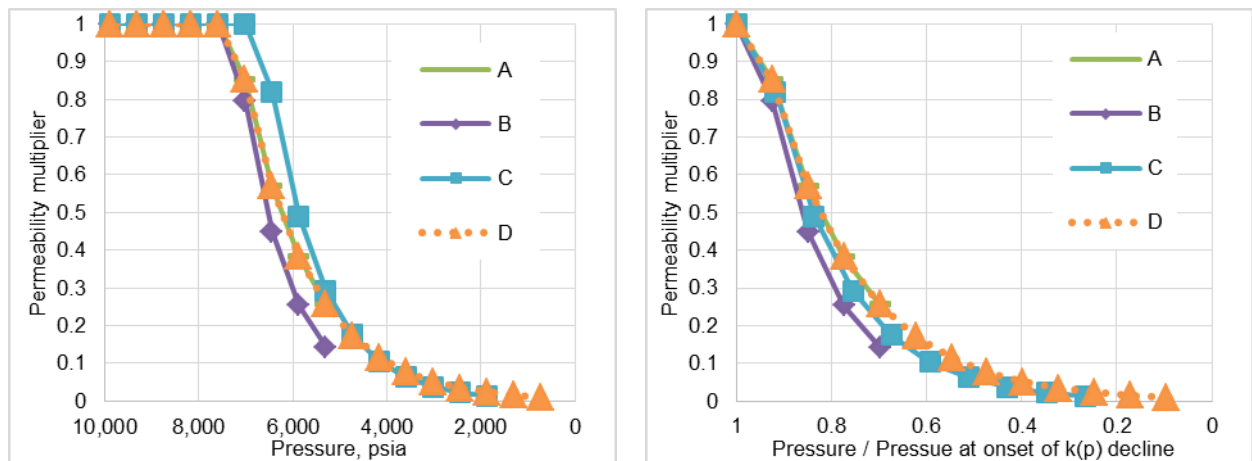
5.1.5.2 A series of trends is observed as production proceeds

On the cumulative production versus normalised rate plots in Fig. R5, red lines are used to highlight three pseudo-linear trends. Most wells follow the same initial pseudo-linear trend corresponding to the matrix zone permeability $k_m(p)$ decreasing with pressure. This is followed by a second linear trend when the fractured zone permeability $k_f(p)$ decreases with pressure. Finally, there is a third linear trend whilst pseudo-skin effects occur.

5.1.5.3 Identical completions result in similar model parameters

Wells A – D have identical completions and were matched using similar model parameters (table R1, Fig. R9). This suggests the model is realistic as it reflects the similar effect on the reservoir of identical completions.

Figure R9: $k_f(p)$ functions used to simulate wells A – D.



5.1.5.4 Comments on matrix zone

Matrix zone permeability starts to decline as soon as the pore pressure decreases. This is consistent with the laboratory experiments used to determine the $k_m(p)$ function. The initial permeability of the matrix zone was found to vary between wells. It was lowest for wells E and F. These wells had the least proppant and a wider cluster spacing than the other wells simulated in this work, except for H. This suggests that the matrix zone of the model does not represent reservoir volume that is totally unaffected by the hydraulic fracturing process, but rather that which undergoes a less pronounced change in permeability. The largest amount of proppant per ft of lateral length was used in wells G and H. The cluster spacing of well H is wider than that of well G yet it still has the higher matrix zone

permeability of the two. This suggests proppant might be the more influential factor but more data is required to confirm this.

5.1.5.5 Comments on fractured zone

The wells with the least proppant, E and F, had the lowest initial fractured zone permeability. Those with the most proppant, G and H, experienced the most gradual fractured zone permeability decline. These observations are consistent with the expectation that proppant acts to maintain the aperture and conductivity of induced fractures.

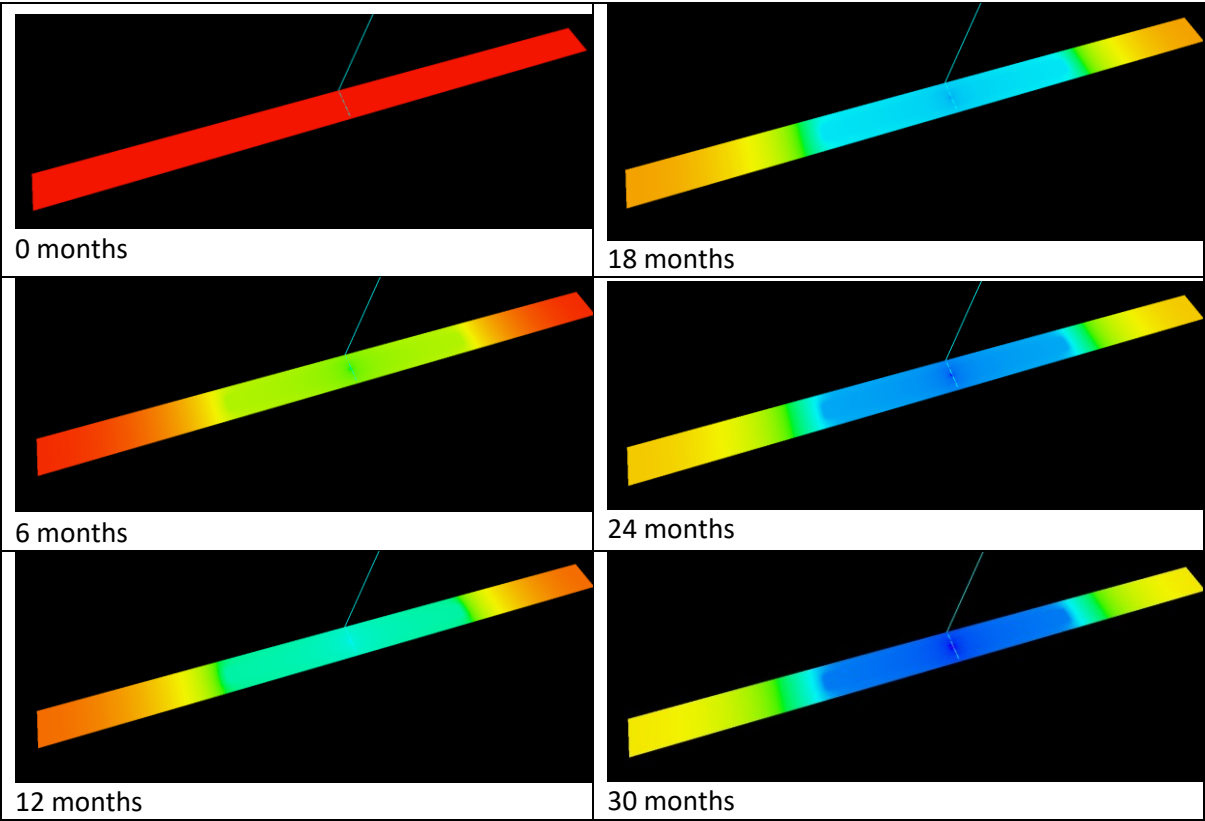
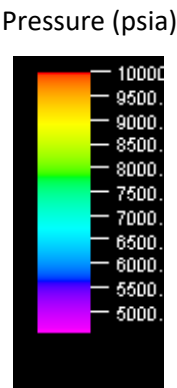
5.1.5.6 Comments on pseudo-skin factor

The onset of the increasing pseudo-skin factor occurs at a BHP of around 3,200 psia (221 bar) for wells E and F. In the initial validation of the model, Kostyleva (2019) found it to occur once BHP had decreased below 2,000 – 4,000 psia (138 – 276 bar). This BHP has not been reached by the other wells yet even though they have been producing for longer than wells E and F at the time of their skin onset. This suggests superior completions (narrower cluster spacing and more proppant) could maintain BHP and postpone the onset of the increasing skin factor.

5.1.5.7 Pressure field during drainage

Figure R10 shows how the pressure field in one repetitive element changes as production proceeds for Well E. This well was chosen because it was history matched for a longer time period than the other wells. The pore volume multiplier remained close to 1 for the duration of this and other simulations so the porosity field is not shown. Significant pressure gradients develop at the limits of the fractured zone suggesting it contributes more than the matrix zone to production.

Figure R10: Pressure field at the depth of the horizontal wellbore (light blue line) for one repetitive element of Kostyleva’s (2019) model of Well E at 6 month intervals during its history matched simulation.

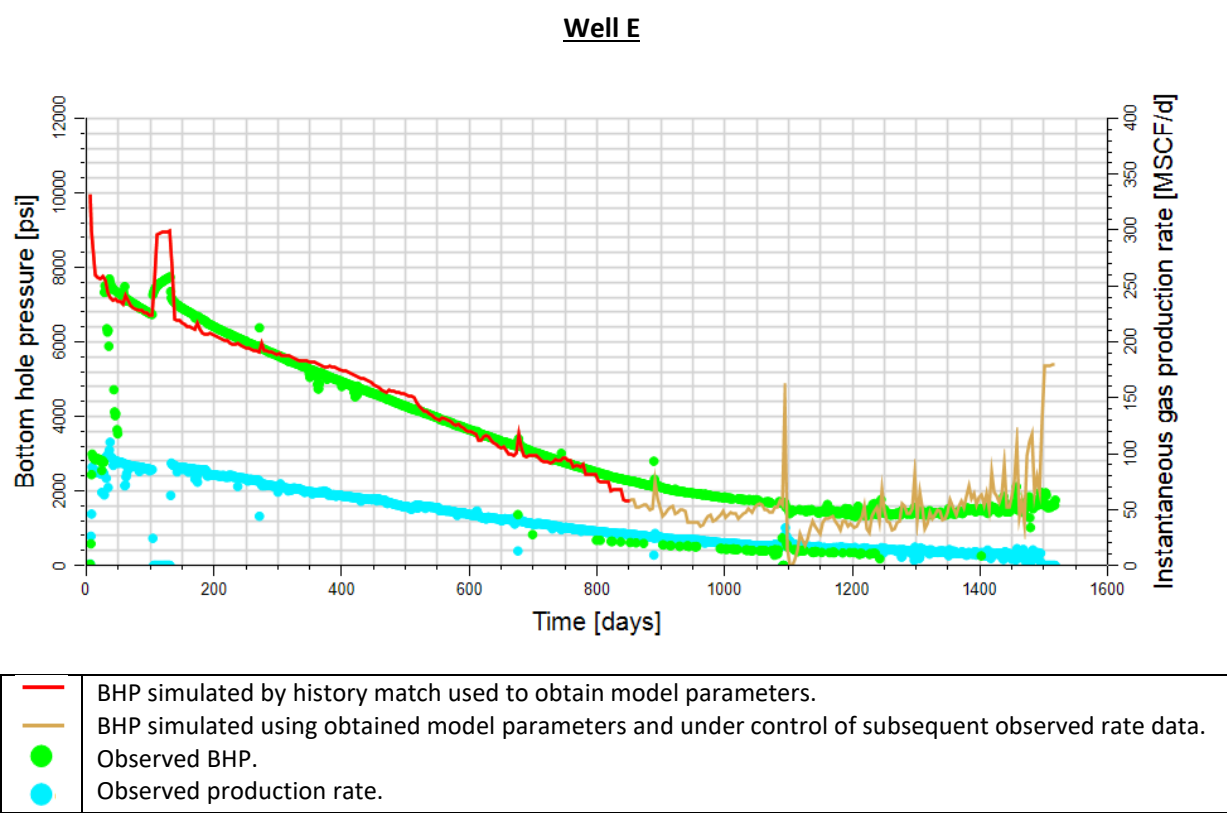


5.1.6 Prediction

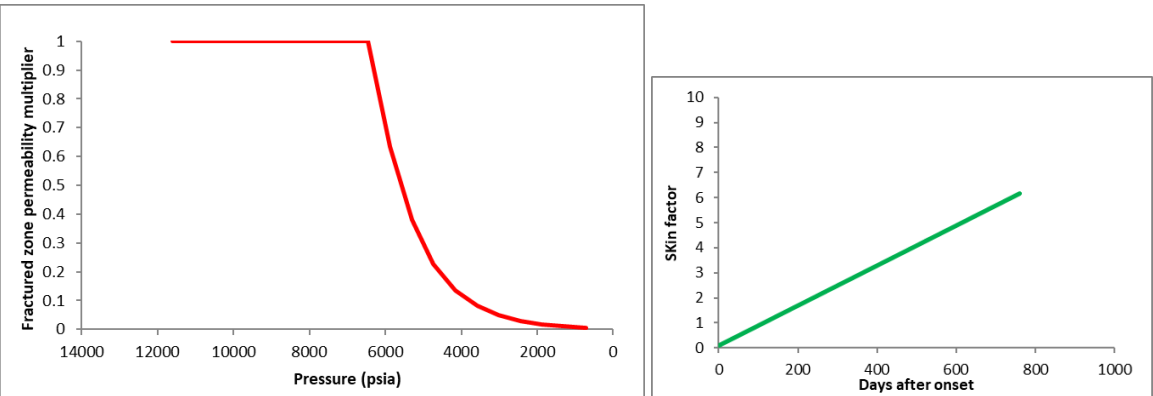
Figure R11 shows the accurate predicted BHP trend for wells E and F, the model parameters used for them and the minimum duration history matches needed to obtain those parameters.

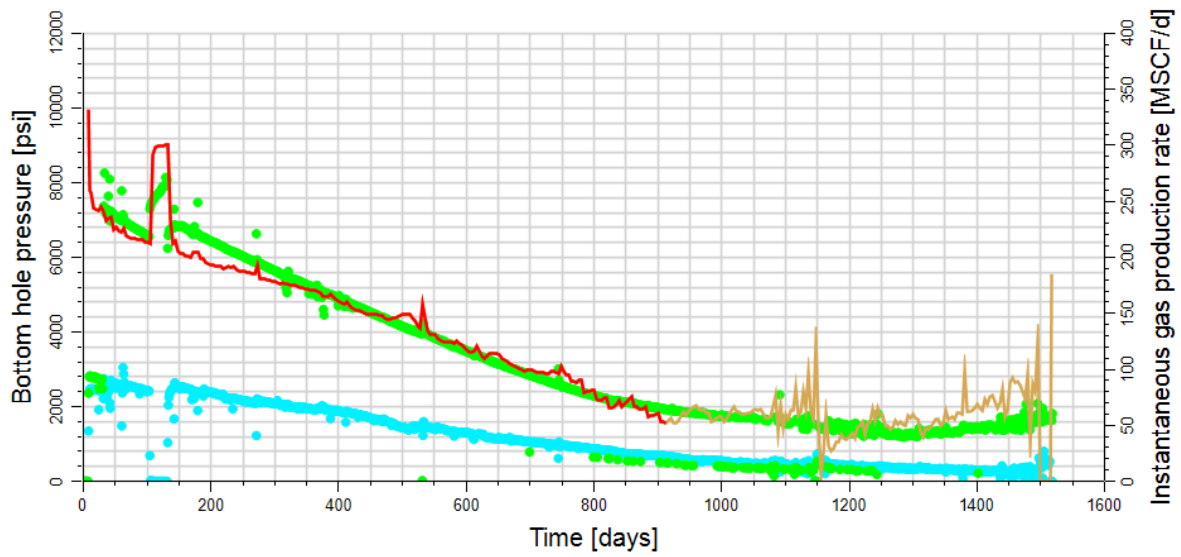
For both wells in figure R11, grids of 36,000 cubic grid blocks, each 6.6ft in length, were used. A total of 7 unknown parameters had to be found by history matching. A history match of similar duration was required for both wells. This was 850 days for well E and 900 for well F. A limitation of Kostyleva's (2019) model is that the skin effect must be reached and continue for long enough to establish its trend before all model parameters are known. It should be noted that observed rate data was used to control both history matching simulations and those intended to predict BHP trend once model parameters had been found.

Figure R11: Predicted BHP trends for wells E and F, model parameters used for them and minimum duration history matches necessary to obtain those parameters.



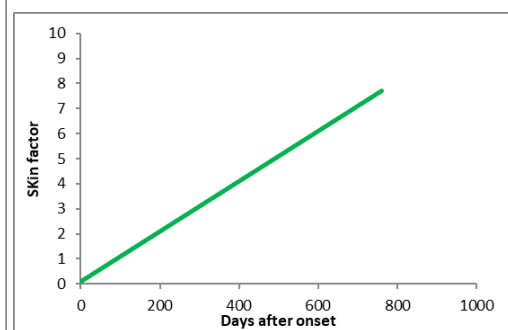
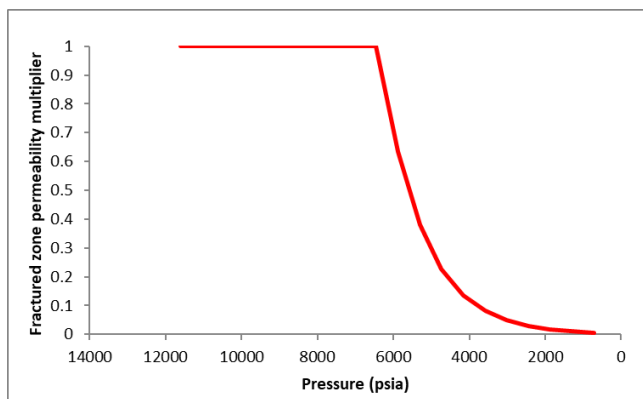
Well	Fractured zone dimensions (ft)		Initial permeability (md)		Days after start of production that skin effect begins	Minimum duration of history match required to obtain model parameters that allow accurate simulation of remaining observed data (days)
	Width	Length	Matrix zone	Fractured zone		
E	32.8	393.7	0.0014	0.08	754 (then increases at 0.008/day)	850



Well F

—	BHP simulated by history match used to obtain model parameters.
—	BHP simulated using obtained model parameters and under control of subsequent observed rate data.
●	Observed BHP.
●	Observed production rate.

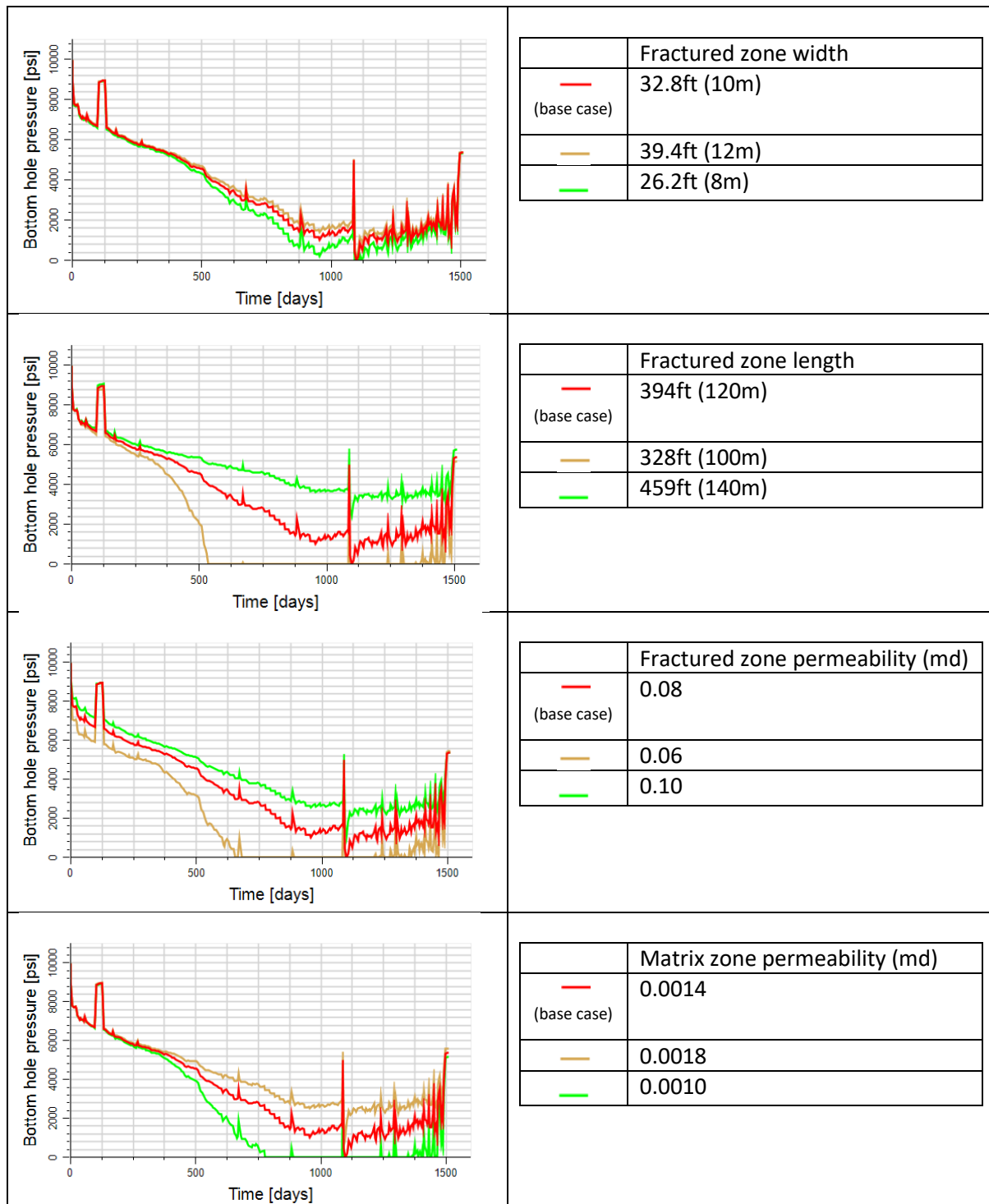
Well	Fractured zone dimensions (ft)		Initial permeability (md)		Days after start of production that skin effect begins	Minimum duration of history match required to obtain model parameters that allow accurate simulation of remaining observed data (days)
	Width	Length	Matrix zone	Fractured zone		
F	32.8	393.7	0.0013	0.065	754 (then increases at 0.01/day)	900

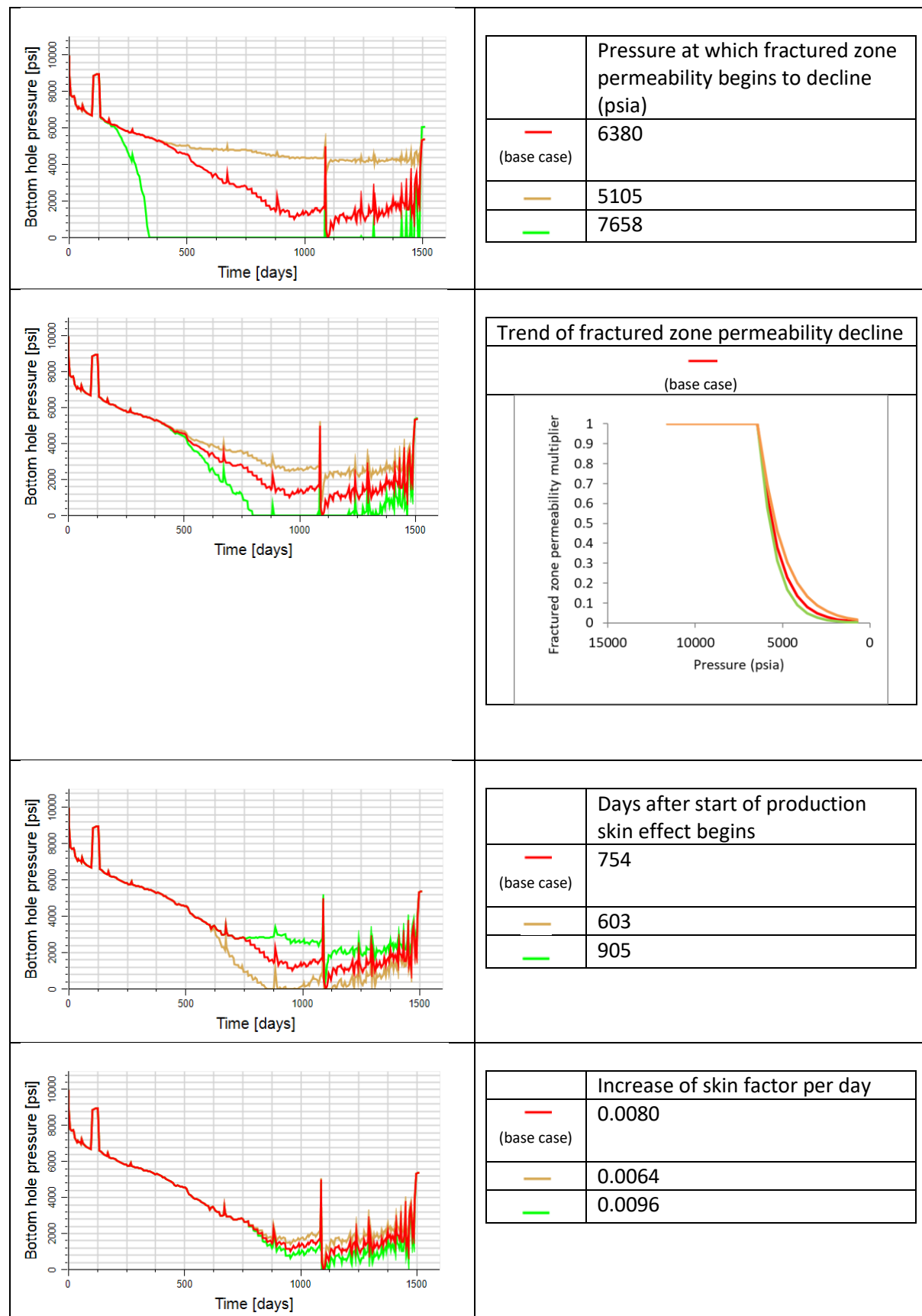


5.1.7 Sensitivity

Figure R12 shows the effect on the simulated BHP trend of varying each model parameter from an accurate history match to well E chosen as a base case. The base case is shown in red throughout figure R12. Parameters with a single value were varied by an amount close to 20%. The fractured zone length affects the BHP trend significantly more than the fractured zone width because of its narrow shape. Altering the fractured zone permeability has an effect on the BHP trend that is noticeable from the start of production. The effect of a different matrix zone permeability is not noticeable until later on during production and becomes apparent gradually. The pressure at which the fractured zone permeability begins to decline appears to have a much greater effect than the trend of the decline itself. This is thought to be due to the steep nature of the decline once the proppant ceases to hold open fractures. The onset of fractured zone permeability decline and the fractured zone length appear to have the greatest effects on the BHP trend. The trend of the fractured zone permeability decline could be thought of as several parameters which must be matched as multiple coordinates must be specified. This results in a larger number of unknowns than the MFZ model during history matching.

Figure R12: Left column shows base case accurate history match to well E and those simulated when one model parameter is varied. Right column gives details of the variation in the model parameter.



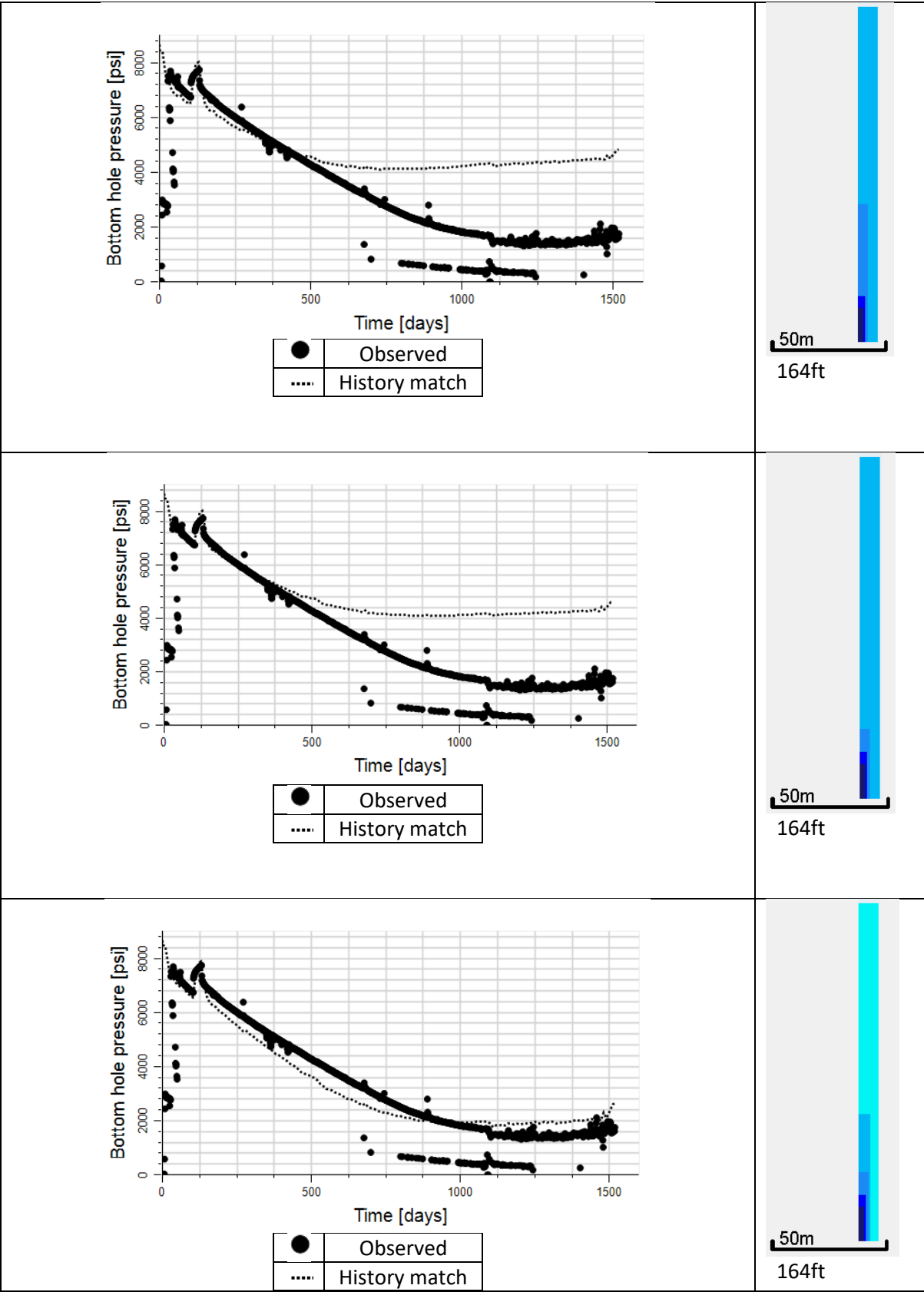


5.2 Multiple Fracture Zone (MFZ) model

5.2.1 Selection of zone map

Figure R13 shows the best history match found for each of a number of zone maps. Based on this, the five zone map was selected for use in subsequent simulations. The need to determine the number of zones could be described as a disadvantage of the MFZ model compared to Kostyleva's (2019). However, once the dimensions of these zones are determined for the MFZ model, they are applied to all wells in the reservoir. With Kostyleva's (2019) model, the dimensions of the fractured zone must be determined for each well. An advantage of the zone map is that it gives a representation of the distribution of fracture compressibility values around the wellbore and therefore the distribution of proppant.

Figure R13: Left column shows best history match obtained with a given zone map. Right column shows the zone map used viewed from above with the cluster located at the bottom left corner.

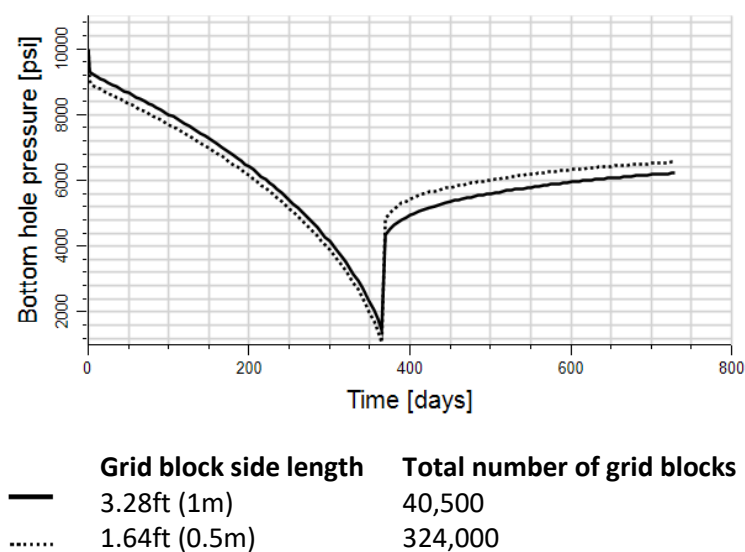


5.2.2 Grid refinement study

Figure R14 shows the bottomhole pressure trends simulated using grids comprising cubic grid blocks of different lengths. The maximum difference in the results obtained from the more and less coarse grids remains in the region of 10%. Therefore, using the coarser 3.28ft (1m) grid blocks can reduce simulation time without significantly affecting the results obtained.

The segment dimensions in this grid refinement study and the element dimensions in that performed for Kostyleva's (2019) model were equivalent since they are those that would be used for two wells with identical cluster and well spacing. A comparison with figure R1 suggests that results from Kostyleva's (2019) model vary less when a coarser grid is used. Whilst it may also appear that Kostyleva's (2019) model requires fewer grid blocks overall, this is only true when the dimensions of its zones allow it. This is because, as with the MFZ model, each block must be assigned to a specific zone. A coarser grid could not be used for the MFZ model whilst preserving the geometry of the selected five zone map.

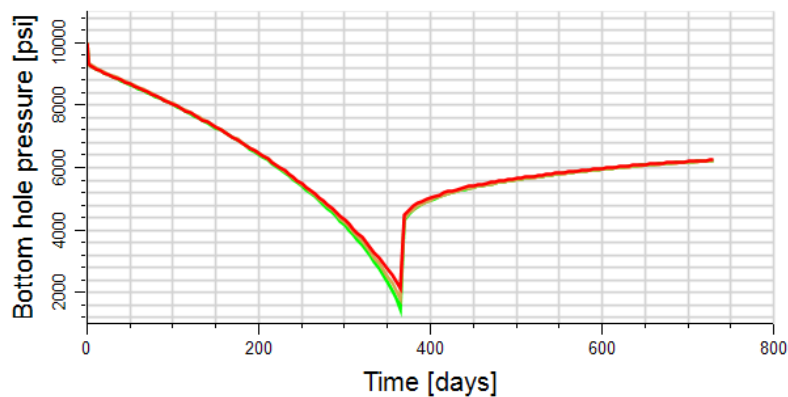
Figure R14: Bottomhole pressure trends simulated with the MFZ model using grids comprising cubic blocks of different lengths.



5.2.3 Aspect ratio study

Figure R15 shows the bottomhole pressure trends simulated using grids containing blocks with different aspect ratios. Whilst the trends and values are similar for most of the simulated period, the results using the highest aspect ratio differ significantly from the others at the end of the drawdown. Based on this, aspect ratios of 1:1:1 or 2:1:1 are considered acceptable but an aspect ratio of 5:1:1 is not. A comparison with figure R2 shows that, whilst the MFZ model appears less sensitive to aspect ratio, it still requires a greater number of grid blocks overall for a well with the cluster and well spacing considered in this and the study of Kostyleva's (2019) model.

Figure R15: Bottomhole pressure trends simulated using MFZ model with grids comprising blocks of different aspect ratios.

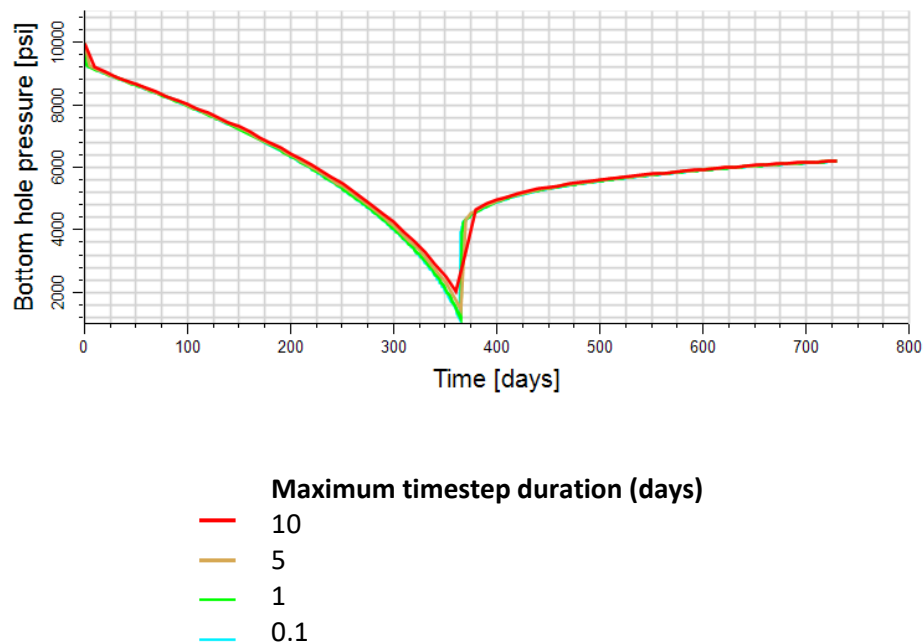


	Longest grid block side length (horizontal direction perpendicular to wellbore)	Length of other grid block sides	Total number of grid blocks
—	16.4ft (5m)	3.28ft (1m)	9x30x30 = 8,100
—	6.56ft (2m)		9x75x30 = 20,250
—	3.28ft (1m)		9x150x30 = 40,500

5.2.4 Effect of timestep duration

Figure R16 shows the bottomhole pressure trends simulated using different maximum allowable timesteps. Only the use of the 10 day maximum timestep produces noticeably different results. Therefore, a maximum timestep duration of up to 5 days is recommended. Figure R3 shows that Kostyleva's (2019) model is less sensitive to timestep duration.

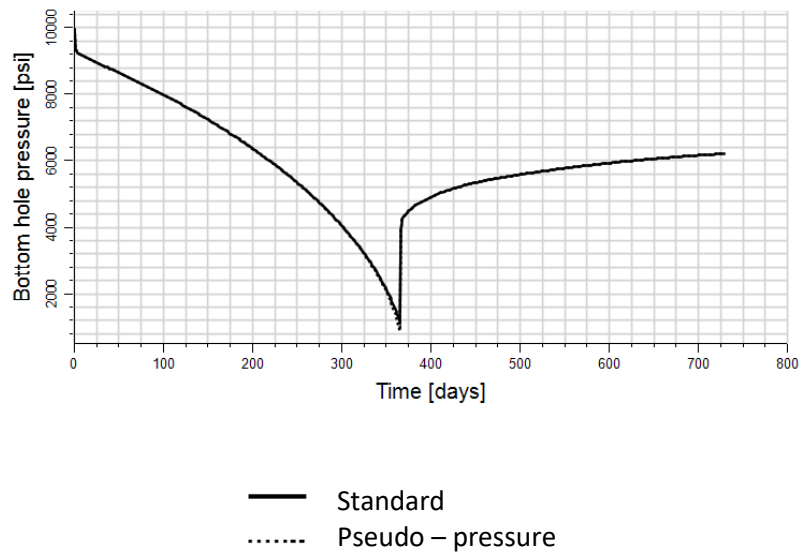
Figure R16: Bottomhole pressure trends simulated using MFZ model with different maximum timestep durations.



5.2.5 Effect of well inflow equation

Figure R17 compares the bottomhole pressure trends simulated with and without the use of pseudo-pressure to account for the pressure dependence of gas mobility when modelling the flow of gas from grid blocks into the wellbore. The trends are almost identical. Figure R4 shows that the effect of using pseudo – pressure is more noticeable for Kostyleva's (2019) model.

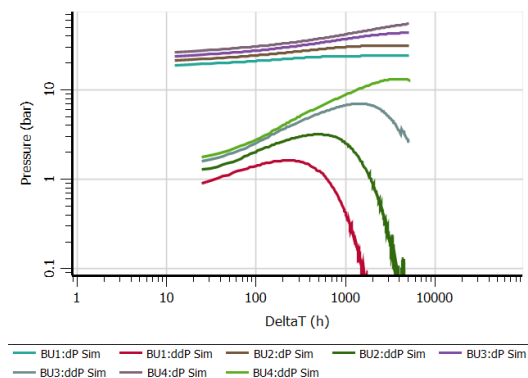
Figure R17: Bottomhole pressure trends simulated using MFZ model with and without the use of pseudo-pressure to model the flow of gas from grid blocks into the wellbore.



5.2.6 Pressure transient analysis

Figure R18 shows the pressure changes and derivatives for the build ups in figure 16. The pressure change that occurs during build ups is clearly affected by reservoir depletion. Earlier build ups approach a stable pressure much sooner.

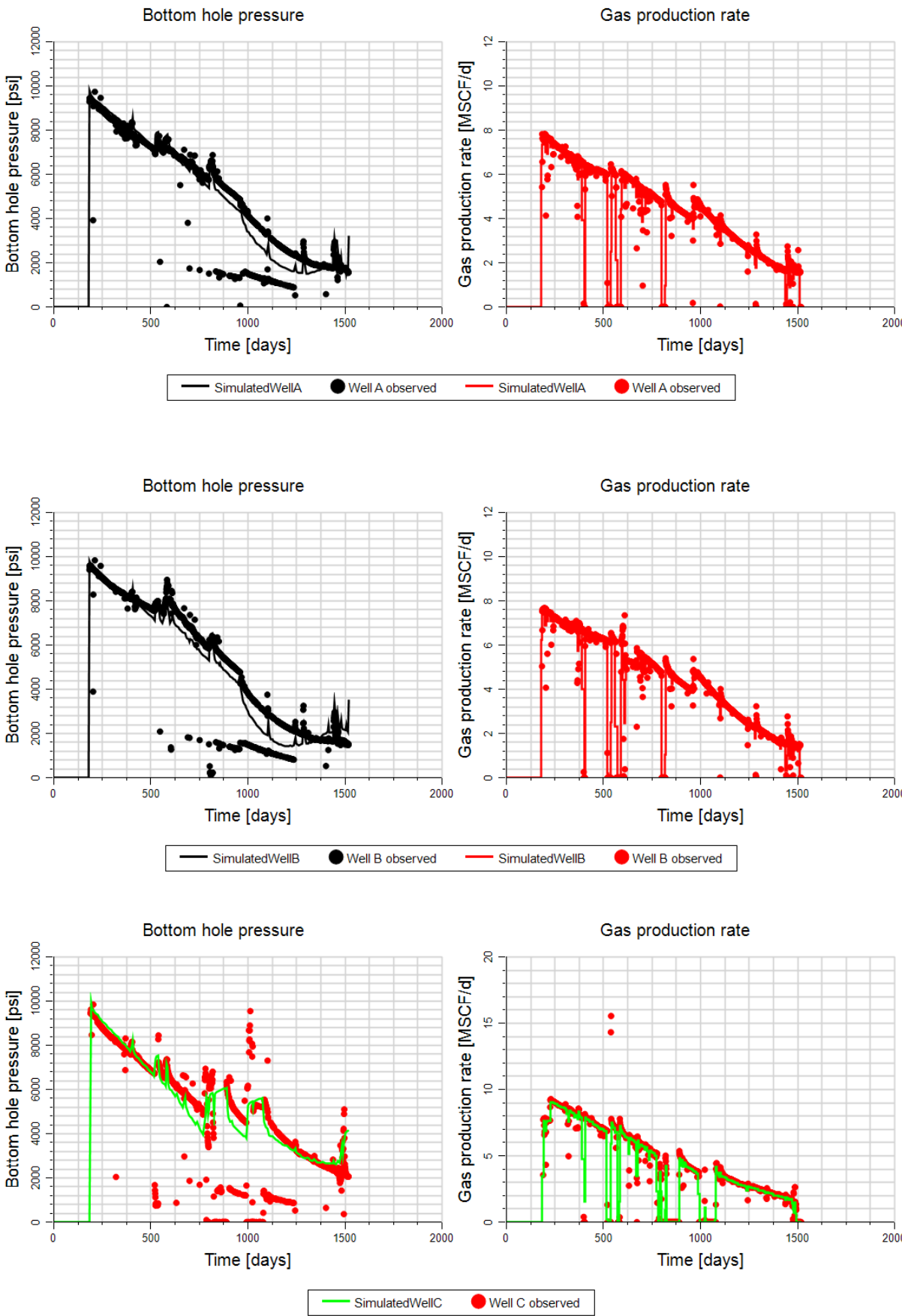
Figure R18: Pressure changes (dP) and derivatives (ddP) for build ups (BU) in figure 16.

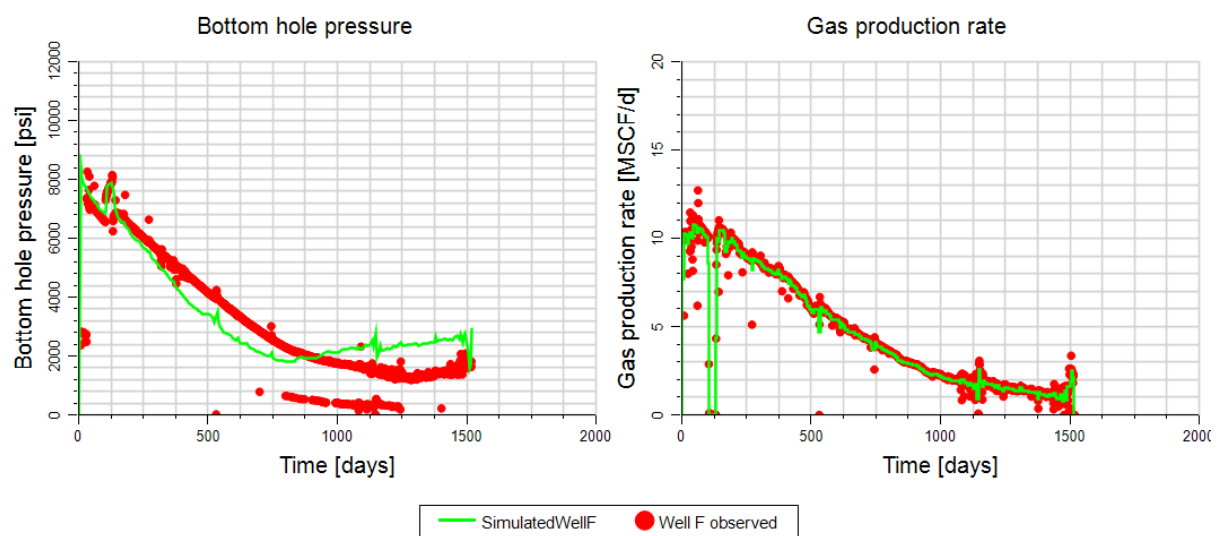
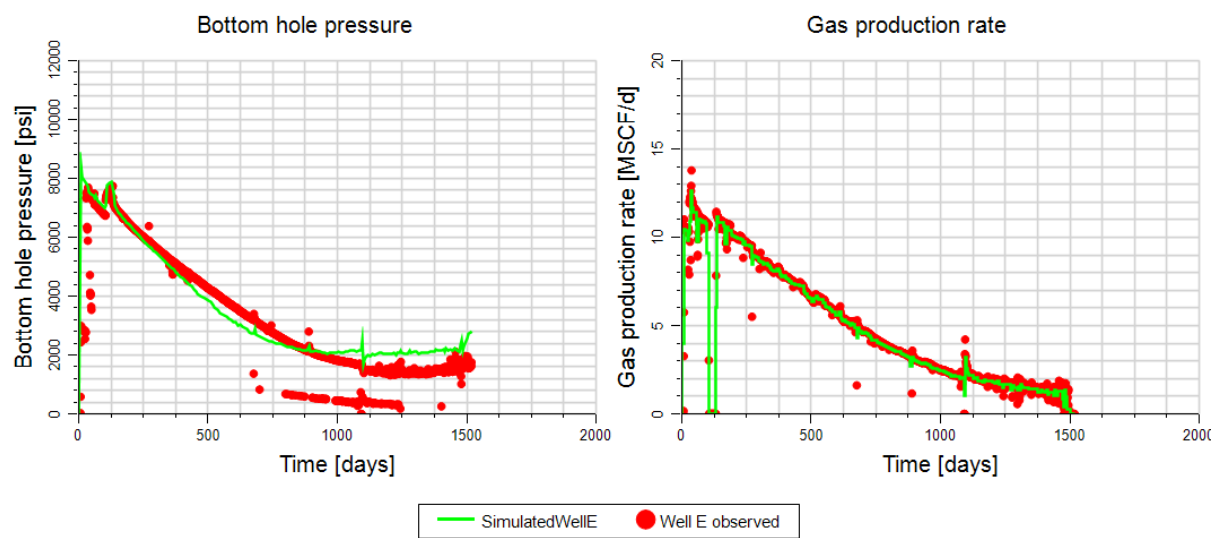
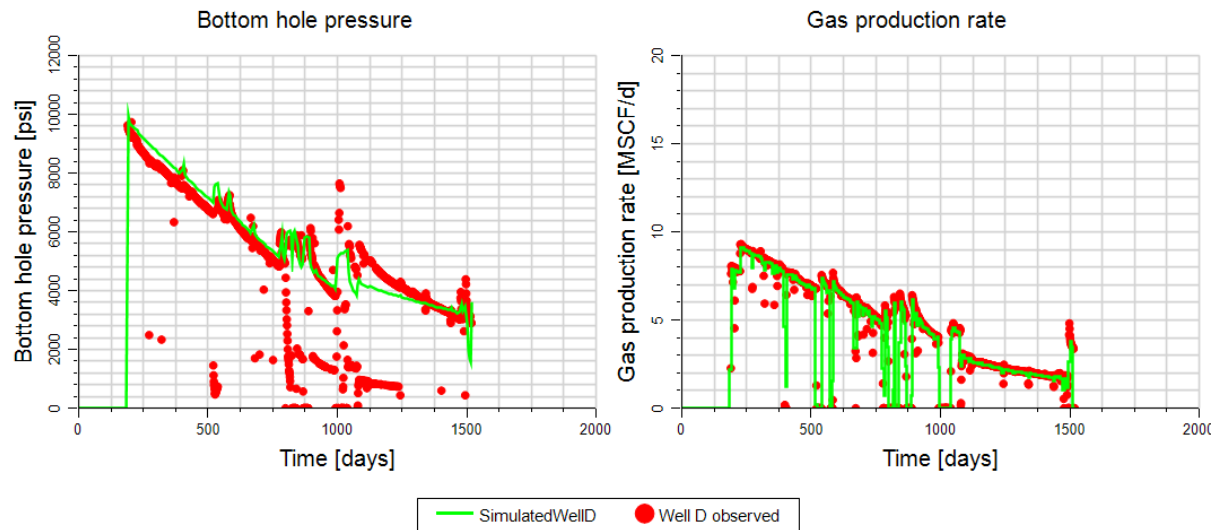


5.2.7 History matching

Figure R19 compares observed data with that simulated using the MFZ model. The history matching is good for most wells despite noticeable noise in observed data. Figure R20 summarises the model parameters used. It is clear from figure R20 that the amount of proppant used has a significant effect on initial permeability but little effect on fracture compressibility of the various zones. This suggests that the fracturing treatment greatly influences the initial properties of the fracture network it opens but has only a limited influence on how the fractures then respond to depletion.

Figure R19: Observed well data and that simulated using the MFZ model. One well shown per row.





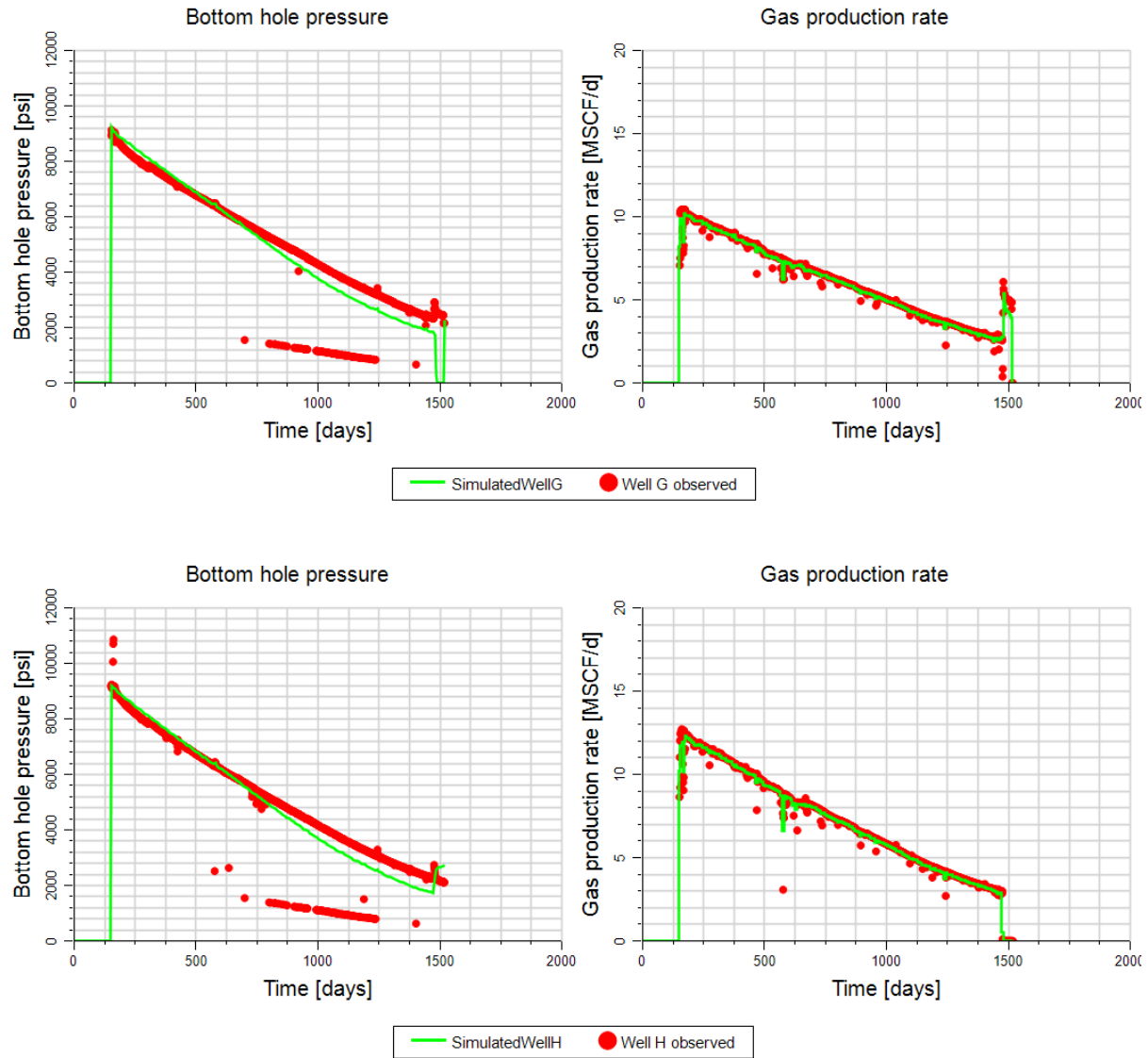
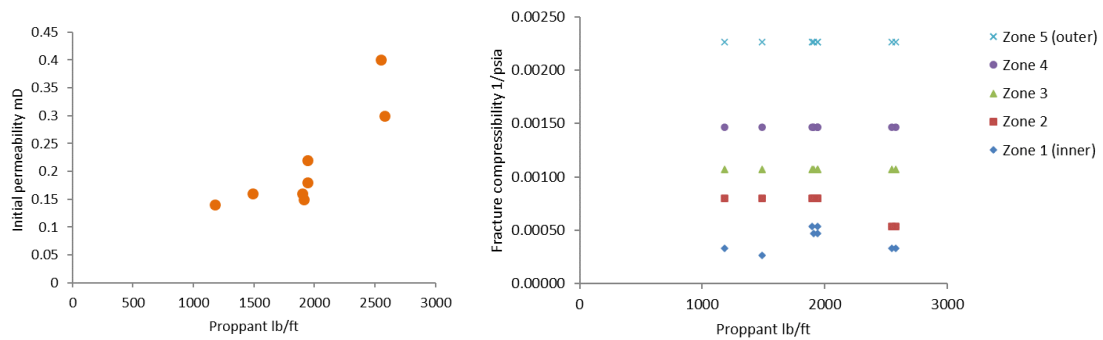


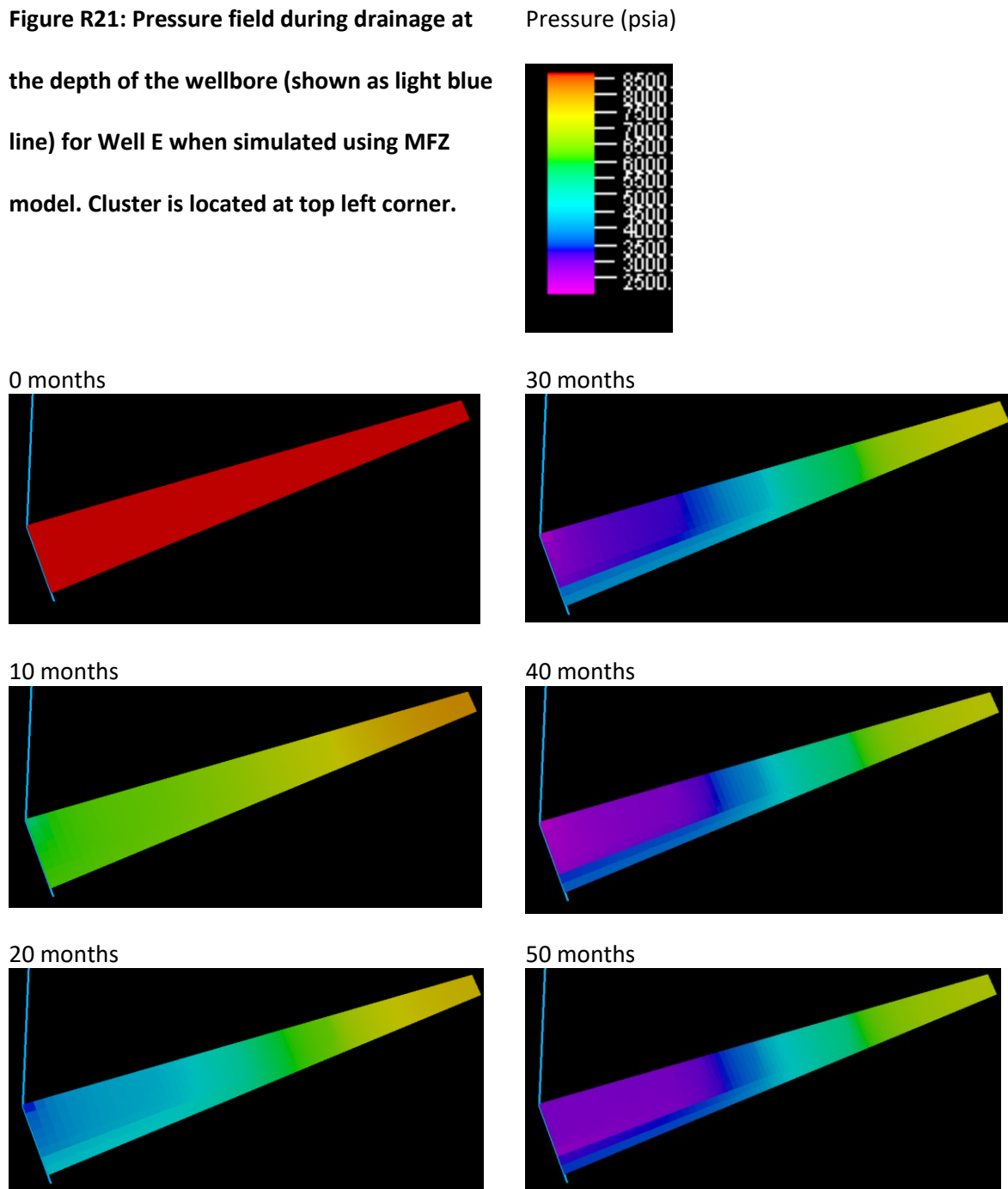
Figure R20: MFZ model parameters used in simulations in figure R19.



5.2.7.1 Pressure field during drainage

The pressure field within a segment during drainage was studied for well E (figure R21). The pore volume multiplier remained close to 1 throughout the simulation. After 20 months, only the half of the segment nearest the wellbore experiences significant pressure changes. This suggests the outer zones of the fracture network contributes little to production after this point.

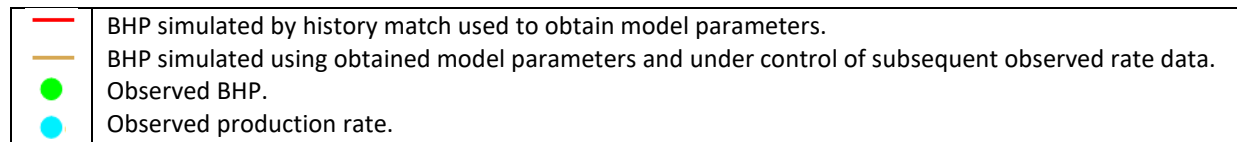
Figure R21: Pressure field during drainage at the depth of the wellbore (shown as light blue line) for Well E when simulated using MFZ model. Cluster is located at top left corner.



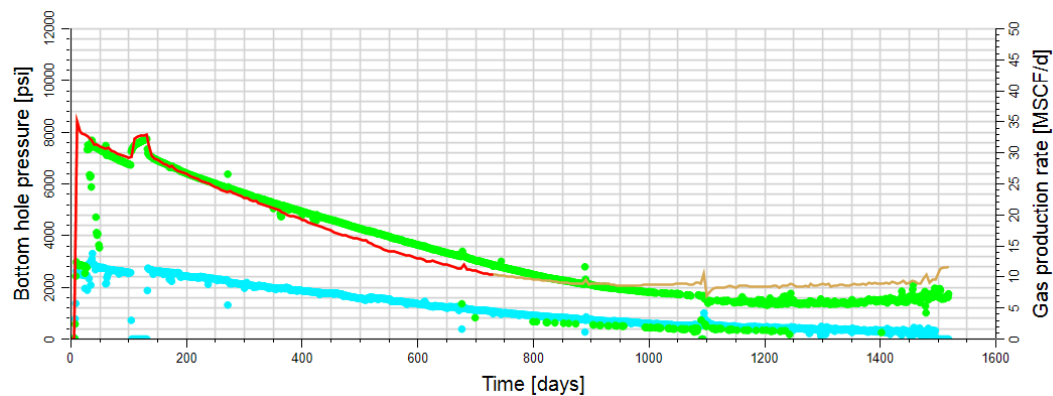
5.2.8 Prediction

Figure R22 shows the accurate predicted BHP trends for wells E and F and the minimum duration history matches needed to obtain the MFZ model parameters for them. Both wells required 730 days of history matching to obtain the model parameters needed to accurately simulate subsequent observed data. With Kostyleva's (2019) model, at least 850 days were required for the same two wells.

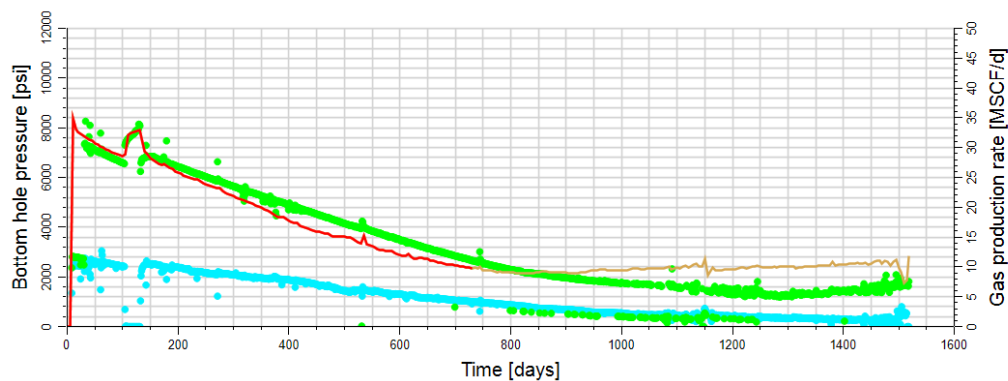
Figure R22: Accurate BHP trends for wells E and F predicted using MFZ model and minimum duration history matches necessary to obtain model parameters for this.



Well E



Well F

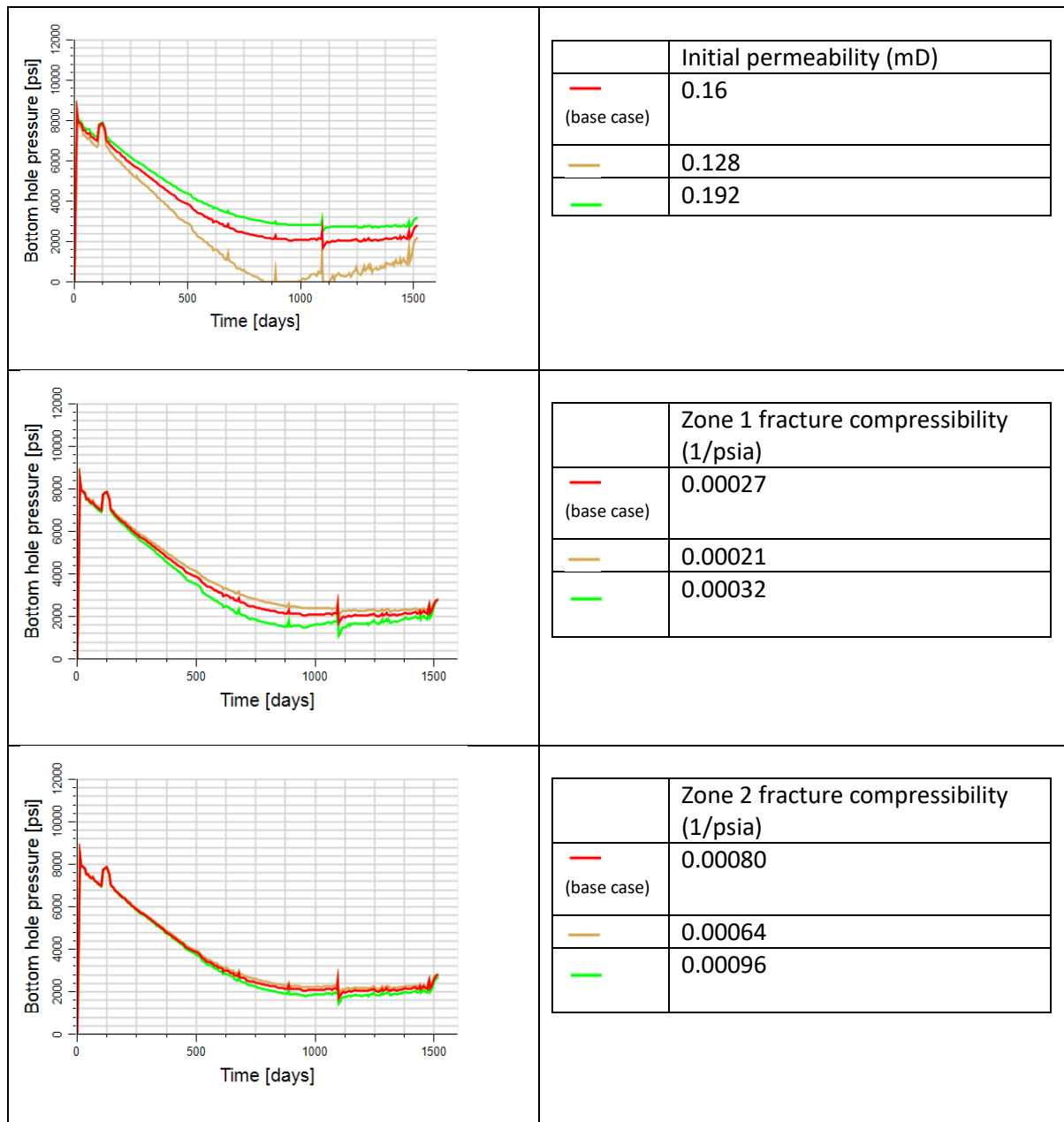


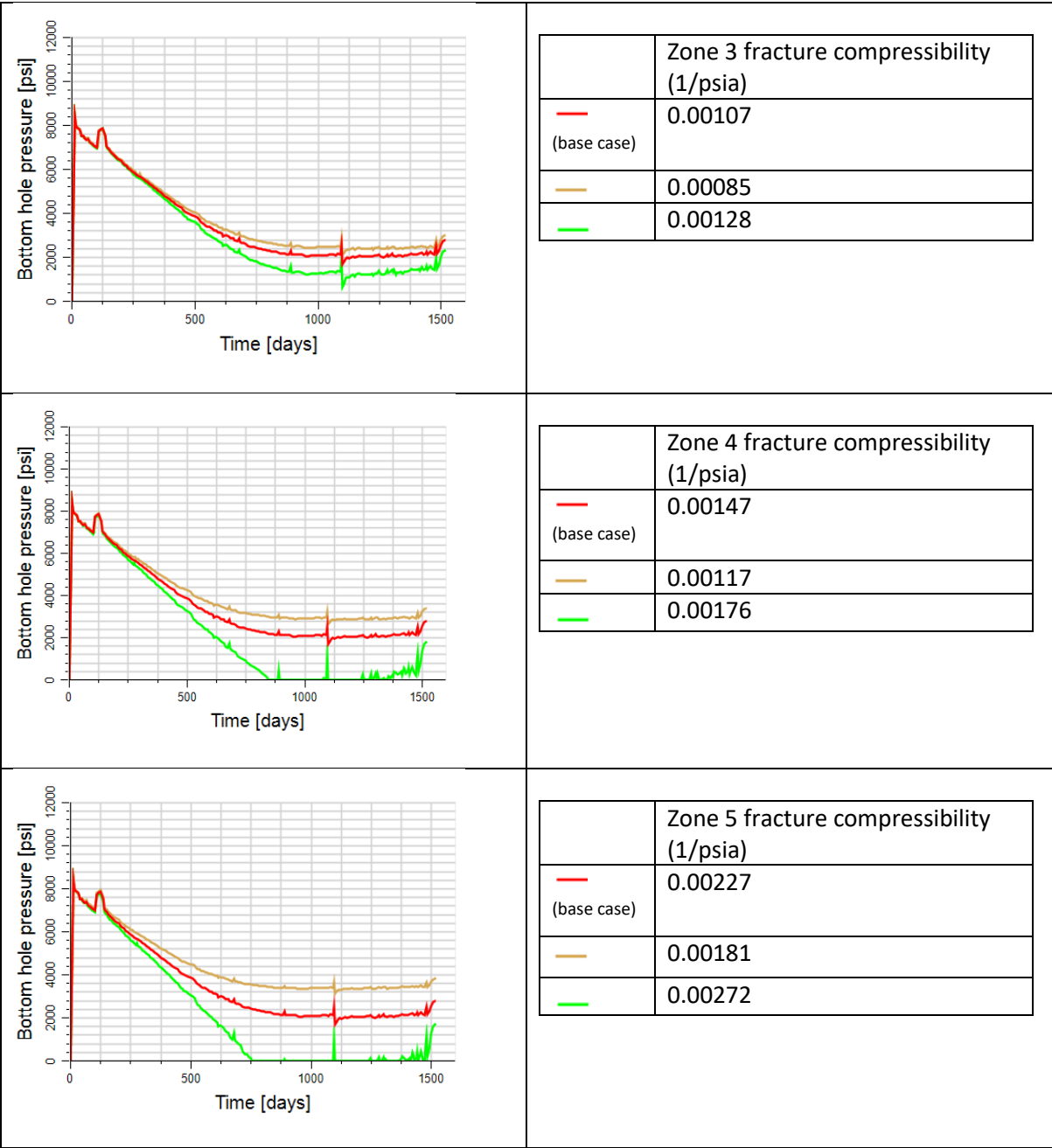
5.2.9 Sensitivity

Figure R23 shows the effect on the simulated BHP trend of varying each model parameter from an accurate history match to well E chosen as a base case. The base case is shown in red throughout figure R23.

The fracture compressibility of the outer zones has a large effect on the BHP trend which is noticeable from early in the production history. This is thought to be because they are the largest zones. Zones closer to the wellbore can be used to make slight adjustments to the later part of the history match. Initial permeability has a large effect on the BHP trend similar to that of the fracture compressibility of outer zones. However, the effect of initial permeability is noticeable even earlier.

Figure R23: Left column shows base case accurate history match to well E and those simulated when one model parameter is varied. Right column gives details of the variation in the model parameter.





5.3 Summary and further comments

A five zone map was selected for the application of the MFZ model to the Haynesville Shale since it contained the minimum number of zones necessary to accurately history match data from it. Fewer zones results in fewer model parameters to determine because a fracture compressibility must be specified for each zone.

The MFZ model is more sensitive to grid refinement than Kostyleva's (2019) model. However, the dimensions of zones in Kostyleva's (2019) model are varied during history matching. Each grid block must be assigned to a specific zone so a coarser grid reduces the flexibility of zone dimensions.

The MFZ model is less sensitive to the aspect ratio of grid blocks than Kostyleva's (2019) model is. Therefore, in some situations, the MFZ model could simulate wells using fewer grid blocks overall.

The effect of maximum allowable timestep duration is similar for both models. An optimum of 5 days is recommended.

Both models were successfully history matched to data from 8 Haynesville Shale wells. Identical completions resulted in similar model parameters. For the MFZ model, the amount of proppant used appeared to have a clear effect on the initial permeability but not the fracture compressibility of each zone. The fracture compressibility values and effect of proppant on initial permeability could be interpreted as field scale descriptions to be applied to all wells.

For wells E and F, the MFZ model required 730 days of history matching to obtain the parameters necessary to accurately simulate subsequent observed data. Kostyleva's (2019) model required at least 850 days.

The number of unknowns to be found by history matching and then used for prediction is arguably much greater for Kostyleva's (2019) model. This is because the fractured zone permeability decline curve is matched one set of coordinates at a time.

The MFZ model has been used to history match the same wells as Kostyleva's (2019) model without the use of a pseudo-skin factor that changes constantly after it is introduced. Such a pseudo-skin factor can be used to match any BHP trend without specifying the reservoir process it represents. This, together with the delayed onset of the fractured zone permeability decline, could be thought of as unrealistic. All parameters of the MFZ model represent specific realistic reservoir processes and attributes. However, the onset of each process considered by Kostyleva's (2019) model can be determined by locating changes in a pseudo-linear trend on a cumulative production versus normalised rate plot. This is not possible for the MFZ model.

6 Conclusions

Both the MFZ model and Kostyleva's (2019) model have been validated by being successfully history matched to 8 Haynesville Shale wells.

Whilst Kostyleva's (2019) model contains an unrealistic pseudo-skin factor and delay in fractured zone permeability decline, all MFZ model parameters represent realistic reservoir properties and processes.

Neither model has a clear advantage over the other regarding grid geometry and other aspects of simulator configuration.

In this work, the MFZ model required a shorter duration history match to establish all necessary parameters for accurate simulation of subsequent observed well data than Kostyleva's (2019) model.

Inspection of the pressure field during simulations using both models suggests that the shale gas reservoir region closest to the wellbore contributes significantly more to production than that further away from it.

In horizontal shale gas wells, the amount of proppant used has a significant effect on the initial properties of the fracture network opened, in particular, more proppant increases the overall permeability of the reservoir containing the fractures if they and the matrix are considered together. The effect of proppant on the compressibility of fractures in the network is less pronounced. The compressibility of a fracture is more influenced by its distance from the wellbore.

7 Recommendations for future research

A strength of this work is its use of extensive sets of real data from the Haynesville Shale. However, history matching to the MFZ model was done after that for Kostyleva's (2019) model and when data sets of a longer duration had become available. History matching Kostyleva's (2019) model to the newer data would allow a better comparison.

This work only considered the Haynesville Shale and concluded that some components of Kostyleva's (2019) model were unrealistic. An application of both models to other shale plays may help to confirm this or reveal the processes those components represent.

A more extensive comparison of the predictive capacity of the two models, using several more wells, is recommended as an area for future research.

8 Nomenclature

α_b	Biot coefficient
ε	Absolute pipe roughness (inches)
φ_f	Fracture porosity
σ_e	Effective stress
γ	Permeability modulus
BHP	Bottom hole pressure
C_f	Formation compressibility
C_{fracture}	Fracture compressibility
D	Tubing diameter (inches)
EUR	Estimated ultimate recovery
f	Friction factor
G_g	Gas gravity
GWR	Gas-water ratio
H	Vertical depth of bottom hole (ft)
JIP	Joint industry project
K, k	Permeability
km(p), no kf(p)	Simulation in which only $k_m(p)$ is entered and there is no variation in fractured zone permeability and no skin factor
km(p), kf(p)	Simulation in which $k_m(p)$ and $k_f(p)$ are used but there is no skin factor
Skin	Simulation using $k_m(p)$ and $k_f(p)$ and a skin factor
K(p)	Permeability as function of pressure
k_i	Initial permeability
$K_f(p)$	Permeability as function of pressure in fractured zone
$K_m(p)$	Permeability as function of pressure in matrix zone
Krg	Relative permeability to gas
Krw	Relative permeability to water
MFZ	Multiple fracture zone (shale gas reservoir model)
P, p	Pressure
p_{decl}	Pressure below which permeability begins to decline
p_i	Initial pressure
P_{wf}	Bottom hole flowing pressure (psia)
P_{wh}	Wellhead flowing pressure (psia)
q_g	Gas flow rate (scf/day)
RISC	Relative intercepted shale capacity
S	Skin factor
s	Variable
SRV	Stimulated reservoir volume
S_{wi}	Initial water saturation
T	Temperature (°R)
THP	Tubing head pressure
TOC	Total organic content
UFM	Unconventional complex fracture propagation model
v	Poisson's ratio
Z	Compressibility factor

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10 Appendix

10.1 Example simulator input for Kostyleva's (2019) model

RUNSPEC

ROCKCOMP -- Generated : Petrel

1* 2 /

TITLE -- Generated : Petrel

'IK'

START -- Generated : Petrel

7 JAN 2014 /

WATER -- Generated : Petrel

GAS -- Generated : Petrel

PETOPTS -- Generated : Petrel

INITNNC /

MONITOR -- Generated : Petrel

MULTOUT -- Generated : Petrel

METRIC -- Generated : Petrel

DIMENS -- Generated : Petrel

8 150 30 /

TABDIMS -- Generated : Petrel

/

GRID

INCLUDE -- Generated : Petrel

'IK_GRID.INC' /

NOECHO -- Generated : Petrel

GDFILE -- Generated : Petrel

IK_GRID.GRID /

INCLUDE -- Generated : Petrel

'IK_PROP_PERMX.GRDECL' /

INCLUDE -- Generated : Petrel

'IK_PROP_PERMY.GRDECL' /

INCLUDE -- Generated : Petrel

'IK_PROP_PERMZ.GRDECL' /

INCLUDE -- Generated : Petrel

'IK_PROP_PORO.GRDECL' /

ECHO -- Generated : Petrel

EDIT

PROPS

```
INCLUDE          -- Generated : Petrel  
'IK_PROPS.INC' /
```

REGIONS

```
NOECHO          -- Generated : Petrel
```

```
INCLUDE          -- Generated : Petrel  
'IK_PROP_SATNUM.GRDECL' /
```

```
INCLUDE          -- Generated : Petrel  
'IK_PROP_PVTNUM.GRDECL' /
```

```
INCLUDE          -- Generated : Petrel  
'IK_PROP_ROCKNUM.GRDECL' /
```

```
INCLUDE          -- Generated : Petrel  
'IK_PROP_EQLNUM.GRDECL' /
```

```
ECHO            -- Generated : Petrel
```

SOLUTION

```
INCLUDE          -- Generated : Petrel  
'IK_SOL.INC' /
```

SUMMARY

```
INCLUDE          -- Generated : Petrel
```

'IK_SUM.INC' /

SCHEDULE

INCLUDE -- Generated : Petrel

'IK_SCH.INC' /

10.2 Example simulator input for MFZ model

RUNSPEC

ROCKCOMP -- Generated : Petrel

1* 6 /

TITLE -- Generated : Petrel

'SIMULATEDWELLE'

WELLDIMS -- Generated : Petrel

1 1 2 1 /

START -- Generated : Petrel

1 JAN 2014 /

WATER -- Generated : Petrel

GAS -- Generated : Petrel

PETOPTS -- Generated : Petrel

INITNNC EDITSUPP /

MONITOR -- Generated : Petrel

MULTOUT -- Generated : Petrel

METRIC -- Generated : Petrel

DIMENS -- Generated : Petrel

9 150 30 /

TABDIMS -- Generated : Petrel

/

GRID

INCLUDE -- Generated : Petrel

'SIMULATEDWELLE_GRID.INC' /

NOECHO -- Generated : Petrel

PETGRID -- Generated : Petrel

'SIMULATEDWELLE.GSG' /

ECHO -- Generated : Petrel

EDIT

PROPS

INCLUDE -- Generated : Petrel

'SIMULATEDWELLE_PROPS.INC' /

REGIONS

NOECHO -- Generated : Petrel

ECHO -- Generated : Petrel

SOLUTION

```
INCLUDE          -- Generated : Petrel  
'SIMULATEDWELLE_SOL.INC' /
```

SUMMARY

```
INCLUDE          -- Generated : Petrel  
'SIMULATEDWELLE_SUM.INC' /
```

SCHEDULE

```
INCLUDE          -- Generated : Petrel  
'SIMULATEDWELLE_SCH.INC' /
```