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Modeling of Induced Hydraulically Fractured Wells in Shale Reservoirs Using 'Branched' Fractals

By

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A report submitted in partial fulfillment of the requirements for the MSc and/or the DIC.

September 2013

DECLARATION OF OWN WORK

I declare that this thesis

'Modeling of Induced Hydraulically Fractured Wells in Shale Reservoirs Using 'Branched' Fractals'

is entirely my own work and that where any material could be construed as the work of others, it is fully cited and referenced, and/or with appropriate acknowledgement given.

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Modeling of Induced Hydraulically Fractured Wells in Shale Reservoirs Using 'Branched' Fractals

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Abstract

Reservoir simulation has gradually become one of the most advanced methods for historical performance analysis and production forecasting for most conventional reservoirs. Unconventional fractured reservoirs still present a formidable challenge to simulate. Simplified reservoir modeling techniques are widely used at present. The recent development of liquid rich gas shale fields presents a new spectrum of problems for numerical modeling in terms of adequate description of in-situ rock permeability, geometry of the induced hydraulic fractures and long-term retrograde behaviour of gas condensate.

Most commonly used simulation models of fractured wells rely on multiple transverse planes each representing a single stage hydraulic fracture to form a network of fractures perpendicular to the wellbore (Vincent, 2011). This approach has difficulties in describing pressure distribution along a single fracture and also within the corresponding drainage area. As a result, the magnitude of pressure depletion and condensate drop-out appear uniform across the fracture-reservoir systems. This can often lead to over-estimation of the rock permeability as well as the contacted reservoir volume.

The focus of this research was on the Kaybob rich gas / retrograde gas condensate region of the Duvernay Shale that is currently being developed in Alberta, West Canada. An actual active production well was used to set up simple 'branched fractal' simulation models which were aimed to represent alternative topologies of a "typical" induced hydraulic fracture. Fluid properties, well completion information and production data were used to build and history matched the model over the 2-year historical period.
The simulations demonstrated that fracture geometry had a substantial impact on predicted condensate rates for the same amount of gas production. Differences in reservoir pressure patterns around the fracture segment and the resulting variations in condensate bank build-up led to a wide range of the predicted condensate recoveries over a typical life time of a shale gas producer.

The knowledge gained from this research may provide valuable insight into the optimal fracturing design, including selection of fracture spacing and screening available technology to create the necessary fracture geometry in order to maximize condensate recovery from a rich gas condensate shale field.

Introduction

Shale Reservoirs

Shale gas reservoirs are formed when layers of sedimentary rock predominantly consisting of very fine clay particles and clay minerals are buried with organic matter and become subject to increasing temperature and pressure with sedimentation over geological time. Hydrocarbon fluids can be sourced from these rocks. The principal flow mechanism in these low permeability formations takes place through a network of permeable conduits in the form of fractures. Fractures can be natural and/or induced. The presence of natural fractures can be a useful indicator of the "fracturability"of the host rock. Nelson (Nelson, 2001) defined a fractured reservoir as *"a reservoir in which naturally occurring fractures either have, or are predicted to have, a significant effect on reservoir fluid flow either in the form of increased reservoir permeability and/or reserves or increased permeability anisotropy"*. Although all reservoirs contain some natural fractures, in unconventional tight/shale reservoirs, the presence of these breaks in the formation is the most critical factor governing fluid flow. Without a significant fracture network, a shale gas accumulation cannot be produced. An important key to economic viability is therefore a dense and extensive network of natural and induced fractures.

A review of conventional reservoir evaluation methods and their applicability to shale reservoirs was carried out by Vanorsdale as early as 1987 (Vanorsdale, 1987). He highlighted that methods such as formation evaluation, analogy to offset wells and material balance are not applicable to gas bearing shales. This is due to production being associated with the existence of natural fracture systems, in addition to the lack of understanding of the recharging mechanisms where communication with adjacent formation over time can lead to failure of the 'closed system' theory often applied. Vanorsdale (Vanorsdale, 1987) also reviewed several other conventional methods including plots of pressure and rate versus cumulative production, well test analysis, reservoir simulation, and decline curve analysis. He concluded that the majority of these techniques often lead to errors in predictions due the difficulty in extrapolation of trends caused by flush production (release mechanism associated with shale gas) and the lack of detailed and representative reservoir and fracture description.

Shale Industry Overview – USA

Although estimates of unconventional gas resources have been higher than conventional gas for well over a decade, only recently shale gas production has become mainstream (Rogers, 2011). The USA shale industry has come a long way from contributing a minority share of overall gas production in the early 2000s to reversing the decline in US gas production.

In the past, extremely low permeability set a major challenge for extracting hydrocarbons from shale formations. Whilst a conventional reservoir typically has a permeability measured in millidarcies, permeability in shale formations can be as low as 10 nanodarcies (Craig, 2009). As a result the hydrocarbons trapped in the shale have been traditionally difficult to extract economically. If a conventional vertical well is drilled into a shale reservoir and not stimulated very little hydrocarbons are produced, and the well is normally not economically viable (The Royal Academy of Engineering, 2012). In order to overcome the permeability problem a combination of horizontal drilling and hydraulic fracturing are used, in addition to other technologies, (Holditch & Madani, 2010).
The US is considered to be the pioneer of the shale gas industry and as a consequence has the highest production and most developed shale gas fields in the world (U.S. Energy Information Administration, 2013).

Barnett

Barnett shale is considered the original shale gas play. Significant shale gas production first started in 2000. As the success of the combination of hydraulic fracturing and horizontal drilling became apparent many operators began to explore and produce. As a result by 2005 Barnett shale was producing nearly 500Bcf per year (U.S. Energy Information Administration, 2013).
Drilling the Barnett shale can be challenging in that most of it is located under the Fort Worth urban area. In order to drill the shale formation, operators are pushing the limits of horizontal drilling. Operators are drilling more wells from the same pad at longer horizontal distances in order to minimize land use (Perryman Group, 2007).

Marcellus

Liquids intensive play. The USGS (United States Geological Survey) estimates there are 84Tcf of recoverable natural gas and 3.4boe (USGS, 2011) in the Marcellus shale.
Development of the Marcellus shale started in 2004 when an operator, Range Resources, realized the similarity between the Marcellus and the Barnett Shale. In order to begin extracting shale gas using hydraulic fracturing and horizontal drilling, Range Resources dedicated 79% of their $1.3 billion 2013 capital expenditure to producing from the Marcellus shale. Figure 3 shows the rapid implementation of horizontal drilling in Pennsylvania where the Marcellus shale is located. During the first 6 months of 2012 over 556Mbbl of condensate was produced in Pennsylvania.
Pennsylvania as a whole has seen a dramatic shift from conventional wells to unconventional. In 2008 only 300 unconventional wells were drilled in comparison to 4511 conventional wells, by 2010 there were around 3000 wells nearly split equally between conventional and unconventional. Although the overall well count is in decline the Marcellus still has more gas-directed drill rigs than any other US gas play and in 2012 became the largest producing gas field in the US (Beckwith, 2013).

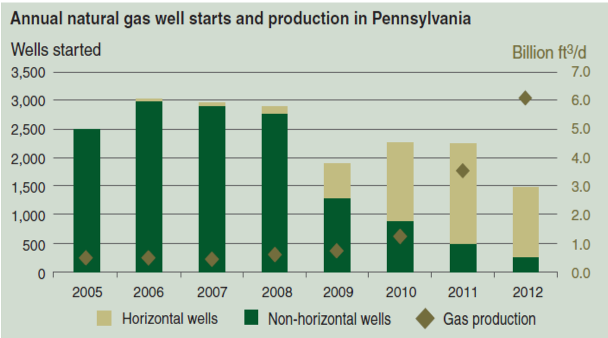


Figure 1 Comparison of horizontal and vertical wells drilled in Pennsylvania from 2005 to 2012. (Beckwith, 2013)

Eagle Ford

The Eagle ford shale is composed of a large amount of carbonate, as a result the formation is very brittle and hydraulic fracturing is much more effective (U.S. Energy Information Administration, 2013). Due to the rapid drop in natural gas prices many operators have become interested in the shale oil potential of the Eagle Ford. In 2010 production exceeded 3.5MMbbl of oil and is on an upwards trend (Marathon Oil, n.d.). Although future Eagle Ford production could be limited by the availability of water in Texas, waterless fracture techniques are being explored (Rassenfoss, 2013).

Shale Industry Opportunities

Outside of the United States, Shale gas exploration and production is in the early stages. It is unlikely that any other country's shale gas industry will develop as rapidly as the US. With over 60% of global drill rigs of which 95% can be used for hydraulic fracturing and horizontal drilling the US is equipped like no other country to exploit its shale resources (White & Rowley, 2013).

Poland

Poland was initially thought to have Europe's best shale prospects with over 792Tcf of shale gas and over 20 operators

acquiring acreage across the country (Sheehan, 2011), however, recoverable reserves have been dramatically reduced to between 12 and 27Tcf (Scislowska, 2012).
Exxon Mobil has pulled out of the country after spending $75 million and drilling 2 wells that were not economically viable due to low gas flow. One of the main issues in the country is a lack of a developed shale industry (Carroll, 2012). Outside of the United States there is a lack of expertise and equipment which can pose serious difficulties in developing shale gas (White & Rowley, 2013). Exxon obviously feel that there is little future potential in the Polish market after relinquishing 3 licenses and selling two to a state owned refinery (Natural Gas Europe .com, 2012)

Canada

According to the CSUG (Canadian Society for Unconventional Gas, 2010), Canada is the world's third largest gas producer and exporter. Gas exports yield revenues between $15-30 billion/year. Since 2000, the country's known gas resources doubled from 390Tcf to 700-1300Tcf with more than 50% associated with tight and shale gas resources.

Canada has numerous shale plays with huge potential and varying geographic characteristics. Technologies similar to those applied in USA have been used to unlock unconventional gas in the region. Recent activity has concentrated on developing plays in British Columbia and Alberta with emphasis on the Duvernay and Montney liquids rich plays. The Duvernay in particular has seen increasing activity over the last 2 years; well count has doubled from 43 to 100 between 2011 and 2012 with 80% of the wells in the Kaybob area and the remaining 20% in the Pembina and East Shale basin (Dittrick, 2013).

The Duvernay Shale basin expands over 50,000 square miles with an estimated 7,500 square miles of thermally mature or 'wet' gas window containing as much as 750tcf of gas. It offers favorable properties for a successful play including good porosity of 3-15%, permeability of 1-5µD, 30-200ft overall thickness, 1-20% total organic content, and a pressure gradient of 0.68-0.81psi/ft. making it over pressured as shown in **Error! Reference source not found.** (Low, 2012). Current estimates of liquid yield are as high as 150bbl/MMscf (Trilogy Energy, 2012).

The Duvernay's longest producing well is Trilogy's horizontal 03-13-060. This well was put on production in April 2011 and has produced a total of 931MMscf of gas and 86Mbbls of condensate since. Two years later and production rates remain high at an average of 700Mcf/d of gas and 66bbl/d of condensate (Trilogy Energy Corporation, 2013).

The Duvernay consists predominantly of silica rich shale, making it more brittle and hydraulic fracturing is therefore more effective, as shown by the Eagle Ford shale. Although production has not yet reached the same scale as the major US plays, the geology is comparable and to date operators have spent an estimated $4.2 billion. As a result future production is thought to have high potential (Smith, 2012). However, as with all newly discovered fields, without long well production histories and sufficient well and core data to build a detailed geomechanical model, major operators/players currently have no reliable means of predicting future condensate production. It is suggested that the majority often resorted to quoting a constant CGR range/value over the lifetime of the field (Low, 2012). This approach is flawed as the condensate production decline rates may not follow the same trend as gas decline rates. This work aims to provide a simple tool to model these reservoirs and forecast future recoveries.

Natural Fractures

The study of production mechanism from naturally fractured shale reservoirs has attracted many workers since the 1980s when shale gas production was achieved from the highly fractured Devonian Shales of the Appalachian basin. Many authors have focused on characterizing individual fractures, fracture networks and multiple fracture sets by investigating parameters such as geometry, orientation, intensity, distribution, connectivity, and most crucially the complexity of the geological nature of the fractures. Walton et al. (Walton & McLennan, May 2013) reviewed the work done on the Devonian shales and concluded that there are three essential elements in modeling the production process from shale systems; desorption of the gas in the matrix, transport of gas from the matrix towards the fracture network, and transport of free gas in the fracture system.

A comprehensive review of the literature on characterizing and modeling naturally fractured reservoirs was carried out by Odunuga (Odunuga, 2012) who also made substantial progress on modeling naturally fractured systems with representative fractal patterns. The main focus was the progress made in modeling fluid flow, drainage patterns and their effect on production trends in complex fractured systems.
Stimulation of naturally fractured reservoirs in order to economically recover hydrocarbons has also been studied for many years however, the interactions between pre-exiting natural fractures and the advancing hydraulic fractures are particularly important in unconventional reservoirs. The ability to effectively enhance production through induced fracturing is dependent on the set of interconnected, naturally occurring fractures which control the reservoir production mechanism (Cipolla, et al., 1988). Cipolla et al. (Cipolla, et al., 2008) associated complex fracture growth with interactions of hydraulic fractures with natural fractures, fissures, and other geologic heterogeneities. Dahi-Taleghani et al. (Dahi-Tagleghani & Olson, 2009) showed that the induced fracture network may exert enough tensile and shear stress on cemented natural fractures that may be

debonded, opened and/or sheared in advance of hydraulic fracture tip arrival.

Hydraulic Fractures

The role of hydraulic fracture geometry and propagation in maximizing well performance is an ongoing area of research. Fisher et al. (Fisher, et al., 2002) and Maxwell et al. (Maxwell & Urbancic, 2002) were the first to associate the existence of large fracture networks in the Barnett shale with stimulation treatments. They also presented initial relationships between the treatment size, shape and production response. Fisher et al. (Fisher, et al., 2004) correlated microseismic-fracture-mapping results to the stimulated reservoir volume and the overall reservoir production. Mayerhofer et al. (Mayerhofer, et al., 2006) went on to show that reservoir performance is associated with fracture geometry and that induced fractures act as a network of very long effective flow paths in a very tight matrix of nanodarcy permeability. Mayerhofer et al. (Mayerhofer, et al., 2010) also supported Fisher's theory by stating that the size of the created fracture network can be approximated as the 3D volume of the microseismic event cloud referred to as the 'Stimulated Reservoir Volume (SRV)'.

Gas-Condensate Reservoirs

Liquids rich gas condensate reservoirs often set a further challenge to evaluate and model due to the rapid decline in production as a result of phase change below the dew point pressure. Production creates a pressure gradient between the reservoir pressure and the flowing bottomhole pressure leading to liquid saturations to build around the well. This phenomenon is often referred to as 'condensate blockage' or 'condensate banking' and is known to cause reduction in well productivity. Furthermore, the actual value of the flowing bottomhole pressure has been found to control the volume and distribution of condensation and the resultant reduction in gas relative permeability.

Vincent (Vincent, 2011) reviewed the literature describing complications with liquids rich formations. He highlighted three key challenges; production of multiple fluid phases and 'mist flow' can increase pressure losses in proppant packs, accumulation of less mobile liquids inside the fractures can decrease productivity in water-submerged portions of the fractures below the wellbore, and condensate banking can reduce effective formation permeability near the fracture face.

Researchers have also shown that for hydraulically fractured wells in conventional reservoirs, the likelihood of condensate drop out is higher near the matrix fracture interface. This is due to the increase in the pressure gradient normal to the fracture. Similar behavior is observed in unconventional hydraulically fractured reservoirs. As a result, the gas relative permeability in the region around the wellbore is reduced. This is detrimental to both condensate and gas production rates over time and thus predicting the magnitude of condensate banking along the hydraulic fractures becomes critical in understanding productivity loss.

The objective of this work is to apply a 'branched fractal' approach to model hydraulic fractures and provide a more accurate predictive technique for estimating fluid recovery over the lifetime of a gas condensate well. This technique is expected to give a closer representation of the real fracture geometry observed in the reservoir. The presence of natural fractures is neglected, so production is dependent on the matrix permeability and gas relative permeability in the region around the hydraulic fracture segment. This more accurate and representative fracture network will be coupled with a Black Oil simulation model to predict flow behavior from the low permeability matrix through the hydraulic fractures and to the well.

Methodology

This chapter discusses the modeling of fracture pattern using the growing branch approach based on a number of mathematical assumptions. It also incorporates the methodology of model building, simulation and calibration of the first three iterations. It finally demonstrates how the models were used to generate a 10 year forecast for gas and condensate production.

Fracture Numerical Model

The fracture pattern was created using a numerical computing software called MatLab (The MathWorks Inc., 2013). This was used to build the growth pattern of the first five fractals using a'branching fractal' approach. The patterns were built based on the assumptions stated below:

- All fractals are vertical planes perpendicular to the well;
- All fractals have a constant length away from the well;
- Fractals grow by means of 'branching';
- Spacing between branches is decreased by ½ after each iteration;
- No overlapping of fractal branches in any region away from the wellbore;

The designed fracture geometry for iterations 1-5 is illustrated in Figure 2 below.

The numerical models were used to estimate the variation in both 2D and 3D fractal surface areas following each iteration stage. An Excel spreadsheet was set up to estimate the reduction in width with increasing number of iterations (Appendix C: Numerical Design Results).

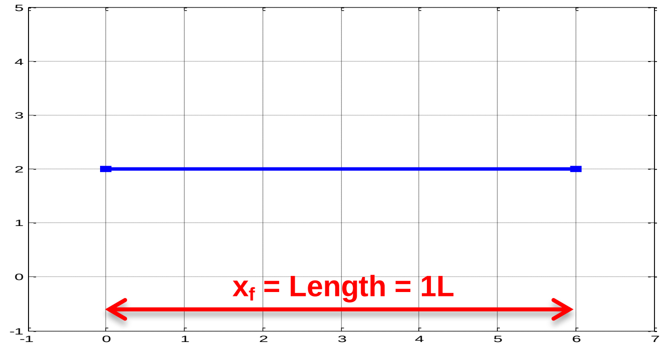
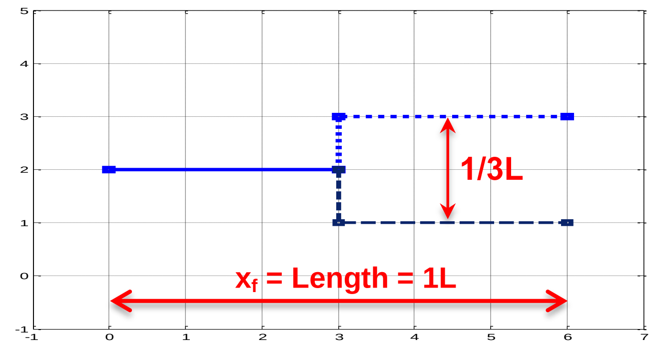
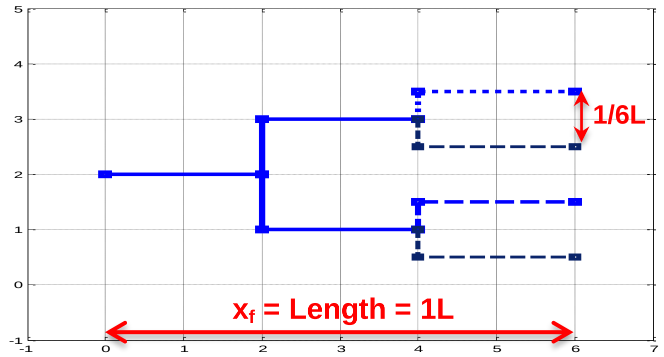
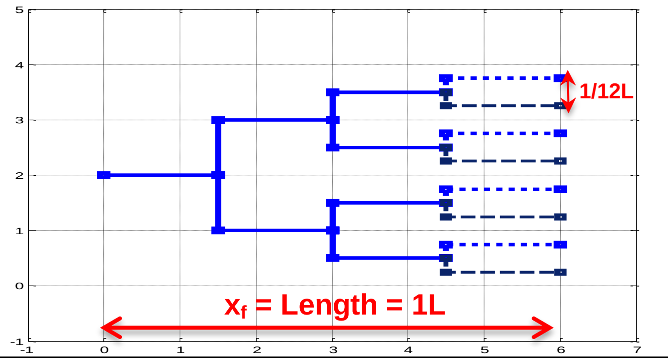
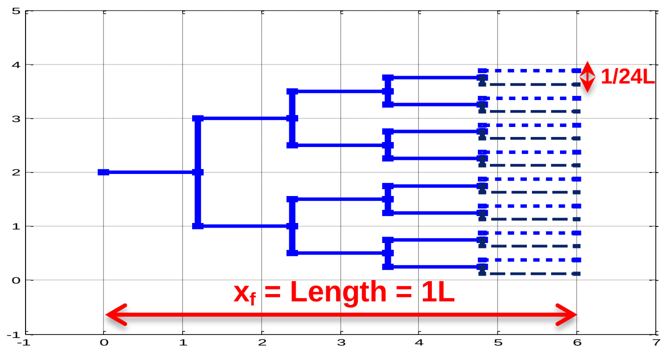
Iteration 1	Iteration #2
	
$2D\ Area\ 1\ for\ 1\ fracture\ stage = 2L$	$2D\ Area\ 2\ for\ 1\ fracture\ stage = \frac{11}{3}L$
Half fracture acts as parent root with length L. (L = 6 units)	Fracture splits to form two branches each with length 1/2L.
Iteration #3	**Iteration #4**
	
$2D\ Area\ 3\ for\ 1\ fracture\ stage = 6L$	$2D\ Area\ 4\ for\ 1\ fracture\ stage = 9.5L$
Two branches split into four branches, each with length 1/3L.	Four branches split into eight branches, each with length 1/4L.
Iteration #5	
	
$2DArea\ 5\ for\ 1\ fracture\ stage = \frac{226}{15}L$	
Eight branches split to form a total of sixteen child branches each with length 1/5 L.	

Figure 2 Fractal geometry design and planar area for one fracture stage

Model Building

A reservoir sector model for a representative element of a fractured horizontal well was built in the simulation software Eclipse 100 (Schlumberger , 2012). The modeled element represents half a fracture stage in a 12 stage fractured well as illustrated in Figure 3. This model allows the user to modify grid geometry to account for the different realizations and to vary matrix and fracture parameters in order to calibrate the model. The following assumptions were made when setting up the model:

- All fractures are open;
- Homogeneous reservoir;
- No flow boundary condition around the well thus the model is draining a constant reservoir volume;
- The hydraulic fractures are represented by high permeability refined grid cells which only contact the matrix at the surface;
- The matrix is represented by a low permeability global grid which contacts the fractures at the surface only;
- Existing natural fractures are not modeled and their permeability is therefore assumed to be the same as that of the matrix;
- Fracture thinning with growth is accounted for by modifying the NTG in the model which is equal to 1 for a matrix grid;
- Production from a modeled sector is estimated by $\frac{1}{24}$*(total well production) assuming a 12 stage hydraulic fracture;
- All local grid refined regions are connected and fluid is able to flow between them.

In order to set up the model, a coarse grid was initially designed as a template for the first three ‘branched’ fractal iterations. The design process was carried out in Excel and aimed to accommodate the most complex ‘Triple fractal’ geometry with the minimum number of coarse grid cells. Special care was also taken to ensure that the fractures always intersected at the center of the cells in both y and x directions to achieve connectivity with the matrix illustrated by the designed coarse grid. Design parameters including fracture length and horizontal wellbore length were based on public domain information for well 03-13-060 (Yoho Resources, 2012). Based on the designed grid, 133 grid cells are required to model half a fracture element. Additional cells were also added in the x direction for improving the visualization of fluid/pressure profiles which increased the total number of coarse grid cells to 266 (Appendix E: Eclipse Grid Design & Input Data).
The well and fracture dimensions used to design the coarse grid are illustrated in Figure 4. Table 1 summarizes the coarse grid dimensions for a half fracture element.

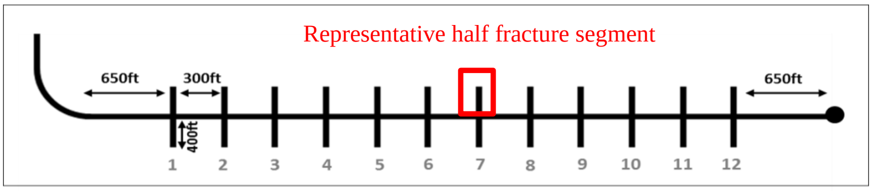


Figure 3 12-stage fractured well dimensions used for coarse grid design

Half Fracture Dimensions				
# Grid cells	Ny*depth (ft.)	Nx*depth (ft.)	Nz*depth (ft.)	x*y*z depth (ft.)
133	19 x 15.40	7 x 57.20	1 x 164	400 x 300 x 164

Table 1 Coarse grid design parameters

The next step was setting up the sector model. Both reservoir and grid properties were defined and a model containing wet gas, oil and water was created. The reservoir dimensions and conditions were extracted from public domain data published by Trilogy and other operators (Smith, 2012). These are summarized in Table 2.

Depth (ft.)	11500	Initial Temperature (°F)	235
Net thickness (ft.)	164	Initial pressure (psi)	8700
Porosity (%)	6	Gas specific gravity	0.71
Permeability (nD)	20	Water specific gravity	1.091
Pressure gradient (psi/ft.)	0.76	Condensate API gravity (°API)	57
Temperature gradient (°F/ft.)	0.0002	Well diameter (ft.)	0.02

Table 2 Model Parameters

The fluid properties were generated using a PVT software called PVTi (Schlumberger, 2012) using data from the PVT Analysis Report for well 03-13-060 (AGAT Laboratories Ltd., 2011). Oil properties were defined by the saturation pressure (in psi), oil volume formation factor (in rb/stb) and the corresponding oil viscosity (in cp) using the PVDO (Properties of Dead Oil) keyword. The rich gas properties were defined by the phase pressure (in psi), vaporized oil-gas ratio for saturated gas (in

stb/Mscf), gas formation volume factor for saturated gas (in rb/Mscf) and gas viscosity for saturated gas (in cp) using the PVTG (Properties of Wet Gas) keyword (See Appendix E: Eclipse Grid Design & Input Data).
Relative permeability data for a three-phase system were generated using Corey parameters for a typical water-wet system with water exponent of 3.0 and oil/gas exponent of 2.5/1.5 respectivily, and the modified Brooke-Corey exponential functions were used to model the three-phase flow (Brooks & Corey, 1964) (Corey, 1954). The single phase gas and water relative permabilities were defined using the SWFN and SGFN keywords, and the three phase relative permeability data when defined using the SOF3 keyword. The fracture relative permeability was also defined for each of the fluids using a convensional method which relies on a straight line relative permeability curve between 0 and 1 (Moinfar, et al., 2011) (See Appendix E: Eclipse Grid Design & Input Data).

In order to initialize the model, matrix permabilities in the x, y and z directions were set to 150 nD. A single well was created in the model and placed in grids # 1:10 oriented in the 'y' direction. The well diameter and kh multiplier were specified at 1 ft. and 0.5 with the latter being a factor which accounts for the well flowing at the left edge of the grid block and not at the center. Production was controlled with a bottomhole pressure of 1000psia and a gas target rate of 111Mcf/d based on the data provided by Trilogy (See Appendix F: Trilogy's Production Data).

The dates were set up in the model to match real production dates for well 03-13-060, the start date was set to June 2011 and model time stepping was adjusted to generate output data every month from June 2011 to June 2013.

Local Grid Refinement

In order to represent the geometries of the first three ' branched' fractal iterations, LGR was used to set up three sector models. There were a total of 10 LGRs in the third and most complex iteration. The procedure for refinement was the same in the horizontal and vertical sections. The refinement method is as follows:

- Horizontal sections were refined by 4x15 in x*y directions;
- Vertical sections were refined by 29x15 in x*y directions;
- LGRs 1, 2, 3, 5, 6, 8 and 9 are horizontal sections;
- LGRs 4, 7 and 10 are vertical sections;
- Iteration 1 consisted of LGR 1;
- Iteration 2 consisted of LGRs 1, 2, 3 and 4;
- Iteration 3 consisted of LGRs 1, 2, 3, 4, 5, 6, 7, 8, 9 and 10;
- All LGRs were connected to allow fluid to flow;
- LGR was applied to 1x3 coarse cells in the x*y directions;
- A column of cells at the tip of the fractal was refined in order to see a clearer pressure profile.

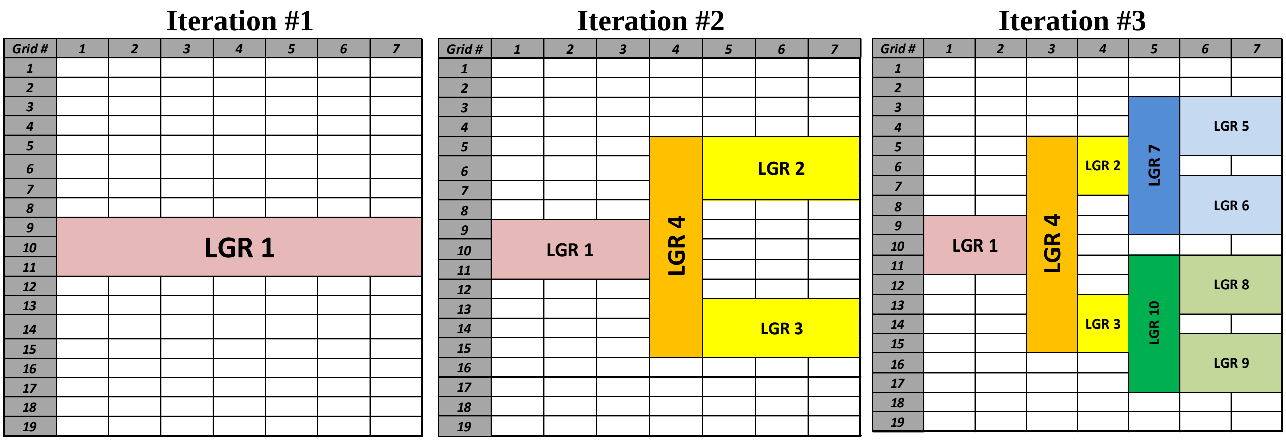


Figure 4 Iterations 1-3 LGRs

Local grid size ratios in the x-direction and y-directions were modified using the HXFIN and HYFIN keywords in the cells where the fracture intersects. The high permeability fracture was represented by cells with 0.05 times the width of the surrounding matrix. Fracture permeability was set to 100 Darcys to initialize the model. The NTG was adjusted in the fracture cells to represent branching and account for fracture thinning. An exponential decline equation calculated in the numerical modeling was used to calculate the reduction in width of the new branches with iteration growth. In the case of the vertical sections, refinement was applied to both x and y directions. The width of the x-direction sections was double that of the y-direction therefore the NTG values applied in the x-direction was set to half that in the y-direction to achieve a fracture of constant width throughout. The resulting NTG values were as follows:

- A NTG of 0.05 was applied to LGR 1 to represent a fracture width of 0.01ft;
- A NTG of 0.023 for LGR 2, 3 and horizontal sections in LGR 4 to represent a fracture width of 0.005ft;
- A NTG of 0.011 for vertical sections in LGR 4 to represent a fracture width of 0.005ft;
- A NTG of 0.011 for LGRs 5, 6, 8, 9 and horizontal sections in LGRs 7 and 10 to represent a fracture width of 0.002ft;
- A NTG of 0.0055 for vertical sections in LGRs 7 and 10 to represent a fracture width of 0.002ft.

Simulation Procedure

In order to calibrate the models, a history matching approach was applied to match the gas production rates recorded by Trilogy (See graphs in Appendix F: Trilogy's Production Data). The recorded rates were analyzed to estimate production from a single half fracture stage where the flow rate for a modeled well segment is approximated at $\frac{1}{24}$*(total well rate) assuming 12 stages. The simulation procedure is summarized in Figure 5.

1. Develop fractal geometry using assigned LGRs based on the iteration number

2. Vary fracture permeability ($K_{proppant\ sand}$) to calibrate initial gas rate (i.e. rate after 1 month of production – July 2011), target rate based on analysed production data was 111Mscf/d

3. Vary matrix permeability (K_{shale}) to calibrate the latter period (i.e. rate after 24 months of production – June 2013)

4. Check Cumulative Gas production with history, if no match has been achieved, go back to step 2 and try a different match

Repeat steps 1-3 for all fractal realizations.

Figure 5 Flowchart showing calibration procedure

Once the models had been calibrated, the time steps were increased in the models to generate a 10 year production forecast from June 2014 to June 2023.

Analysis and Results

Fractal Numerical Results

The 2D surface area representing a half fracture element was calculated as shown in Figure 2 above. These calculations were carried out for the first 5 iterations assuming constant height and width. In order to account for the thinning effect with fracture growth, a second set of calculations was carried out where a constant proppant volume was used to estimate the reduction in width and increase in 3D contacted area. The proppant volume per half fracture stage was calculated based on an average total injected proppant volume of 2200tonnes (Yoho Resources, 2012) of sand with 40% porosity and 165lb/ft^3 density.
Two exponential functions were found to give the best fits with the calculated dimensionless width and area of the first 5 iterations of the 'branched' fractal approach. The curves in Figure 8 illustrate that as the width of a branched segement decreased exponentially, the reservoir area contacted by the fractal segement increases exponentially.

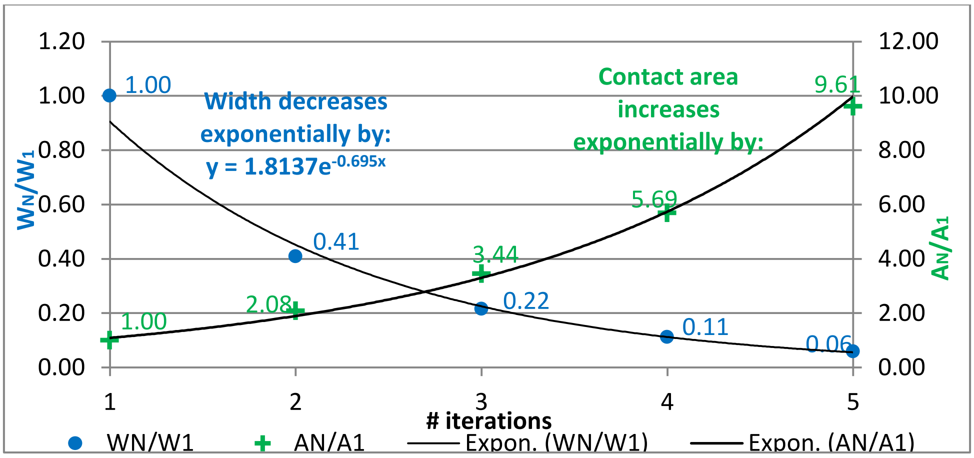


Figure 6 Area and width variation with # of iterations

The results from the numerical analysis suggests that despite branches becoming thinner with more complex geometry, the overall contacted reservoir area is simultaneously increasing which will impact production as fluid is able to flow throw a larger area from the matrix to the high permeability fracture.

Simulation Results

The simulation results showing the history match and forecasted volumes for a representative half fracture element are given in Table 3 below.

Time	History		Single Fracture		Dual Fracture		Triple Fracture	
	CUM Gas, MMscf	CUM Cond, MStb	CUM Gas, MMscf	CUM Cond, MStb	CUM Gas, MMscf	CUM Cond, MStb	CUM Gas, MMscf	CUM Cond, MStb
2 Years	38	3.8	38	3.5	38	3.7	38	4.1
10 Years	-	-	128	8.2	129	10.1	129	11.1

Table 3 Summary of simulation results for a half fracture sector

The fracture and matrix permeabilities were varied in order to achieve a history match. The fracture permeability was used to calibrate the rate at the start of production; this parameter controls the initial fluid flow to the well from the region in contact with the fractures. The matrix permeability controls fluid flow through the matrix over time to replace the fluid near the fractures which has been removed and produced, therefore this parameter was adjusted to match the rates by the end of 2-year historical period.

The quality of the history match was controlled by matching the initial gas rate and the cumulative gas and condensate production volumes after 2 years. These were matched as closely as possible while observing the gas and condensate rates at late time to ensure that they remained within an acceptable error to the recorded rates. Overall, good matches were achieved for all three geometries as illustered by Figure 7, the optimum combinations for fracture and matrix permabilities achieved for the history match are given in Table 4.

Parameter/Model	**Single**			**Dual**			**Triple**		
Branch	Primary	Secondary	Tertiary	Primary	Secondary	Tertiary	Primary	Secondary	Tertiary
$K_{fracture}$ (nD)	100	-	-	130	100	-	250	130	100
K_{matrix} (nD)	150			100			50		

Table 4 History matched parameters

The results show that the matrix permeability decreased significantly in the Dual and Triple models in order to get a history match. The predicted matrix permeability value required to history match the Triple fracture model is also much closer to the estimated Duvernay shale permeability range of 20 nano-darcies published in literature (Trican, 2013). This indicates that the models give better estimates and require little adjusting compared to the Single fracture. The table above also indicates that the optimum matches were achieved when the fracture permeability was decreased as branches grew; this represents the natural decrease in fracture permeability as we move from the stem to the secondary and tertiary branches.

The final pressure profile for a Single fracture seen in Figure 9 shows a less uniform pressure distribution within the drainage area of the stage fracture, when comparing this to pressure profile in Figure 10 and Figure 11, both the Dual and Triple models give a larger drained area over time in addition to less depletion around the fracture segment.

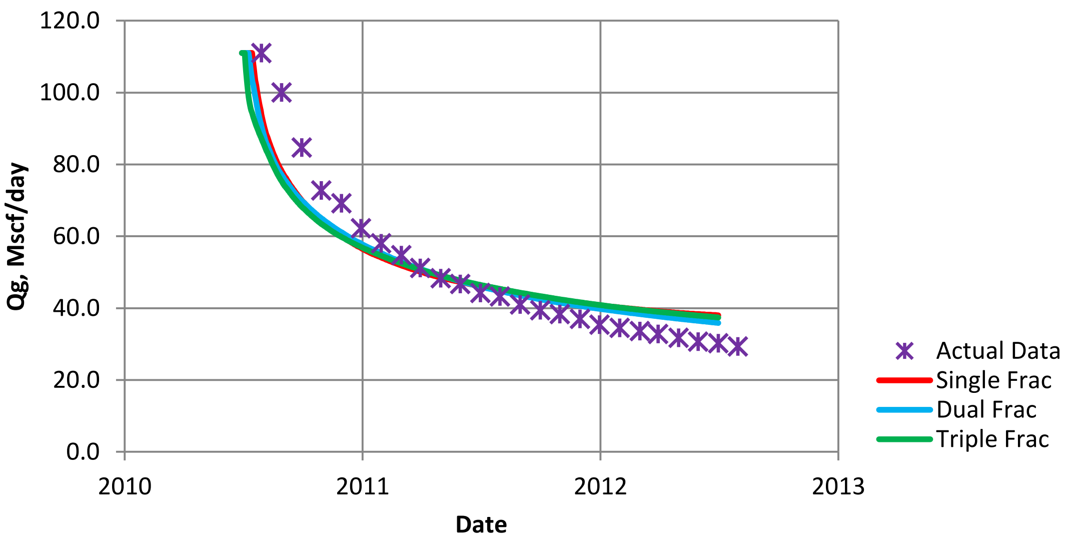
A similar profile is observed for the oil saturation, Figure 9 shows the condensate drop-out for a Single fracture where a large condensate bank can be seen around the fracture segment after 10 years, whereas the other two models give a more dispersed condensate profile which when combined with a more uniform pressure distribution around the facture, can lead to smaller in-situ condensate losses with the same gas recovery resulting in larger recoverable condensate volumes.

The Dual and Triple models also predicted a better CGR profile over the historical period. The GCR graph in Figure 7 shows a stable and consistent profile with little jumps for the recent historical period, unlike the Single fracture model where a clear decline can be observed, likely to have been caused by condensate blockage. However, all three models showed CGR profiles which only match the historical data over short periods. The single fracture model gave a better match with historical data at early time but continued to decline when historical data showed an increase. The Dual model matched the historical CGR at several points however remained stable even at late time, while the Triple fracture model generated much higher CGR trend throughout the 2 year period which also remained stable at late time when compared to historical data. This can be related to friction losses around the fracture segment, maximum losses are observed from the fracture segment nearest to the well as it contributes most to the flow. However for the Dual and Triple fracture models, as gas rate dops, remote segments start producing and have smaller losses, in effect this will result in a steady increase in the SRV with time.

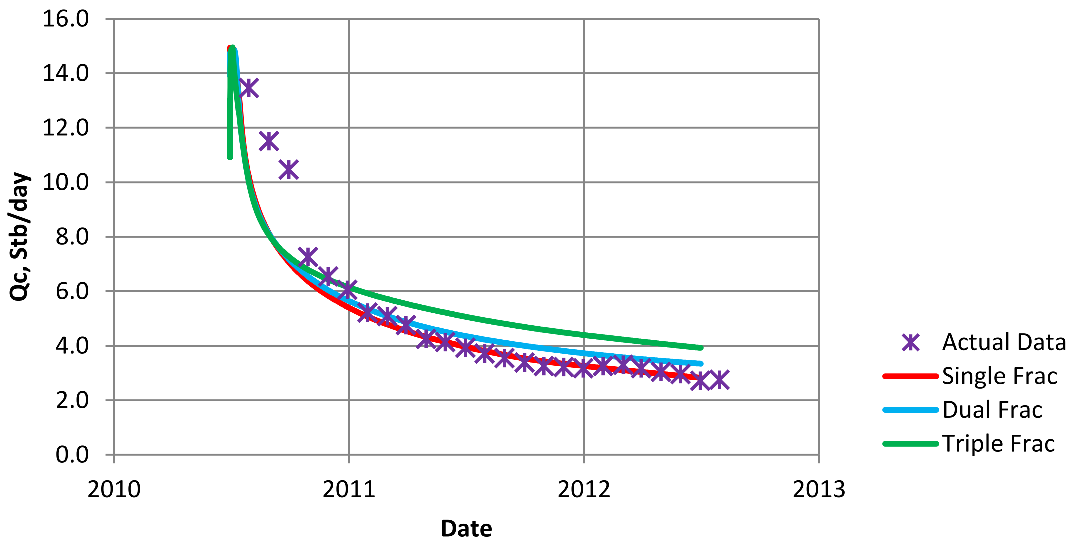
After generating the forecasts, all three models were found to give similar cumulative gas forecasts after 10 years as seen in Figure 8. The models estimated a cumulative gas volume of around 3.1Bcf by 2023 (129MMscf*24) which is consistent with Trilogy's analytical estimate of 4Bcf over the lifetime of the well (Trilogy Energy, 2012). However, the Triple Fracture model predicted much higher cumulative condensate volumes by 2023, the condensate volume estimated from this model was 26% larger than that from the Single fracture. Trilogy has not published any recoverable condensate estimates for this well as it is not possible to predict this using the conventional analytical method.

History Matching Results

Gas Rate 2011-2013



Cond Rate 2011-2013



CGR 2011-2013

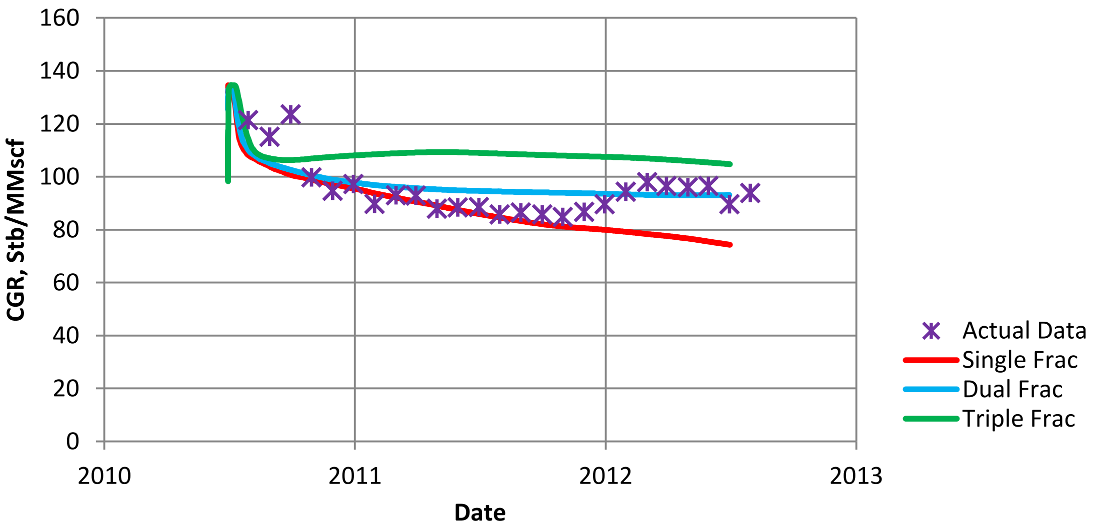
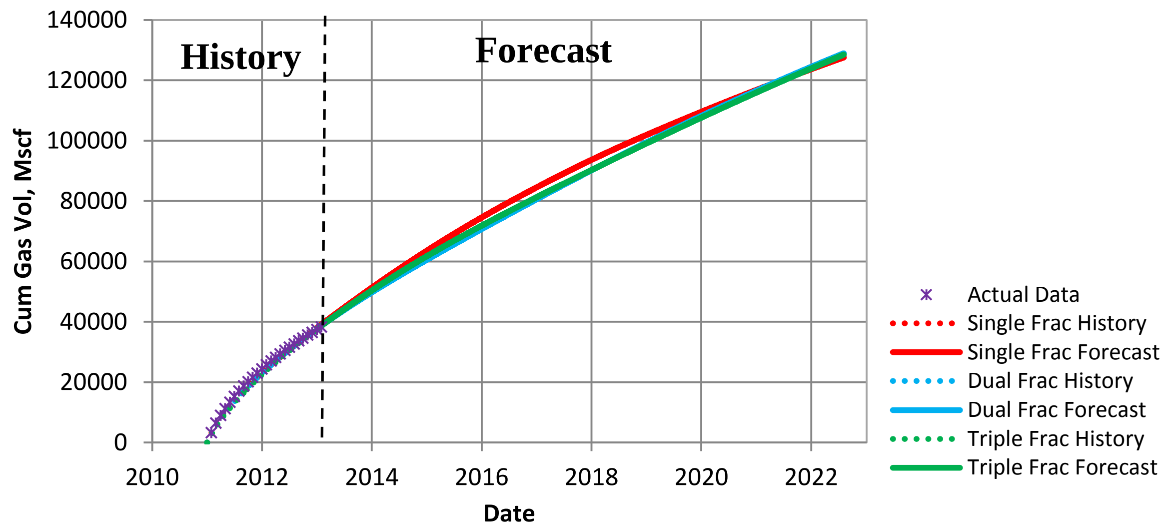


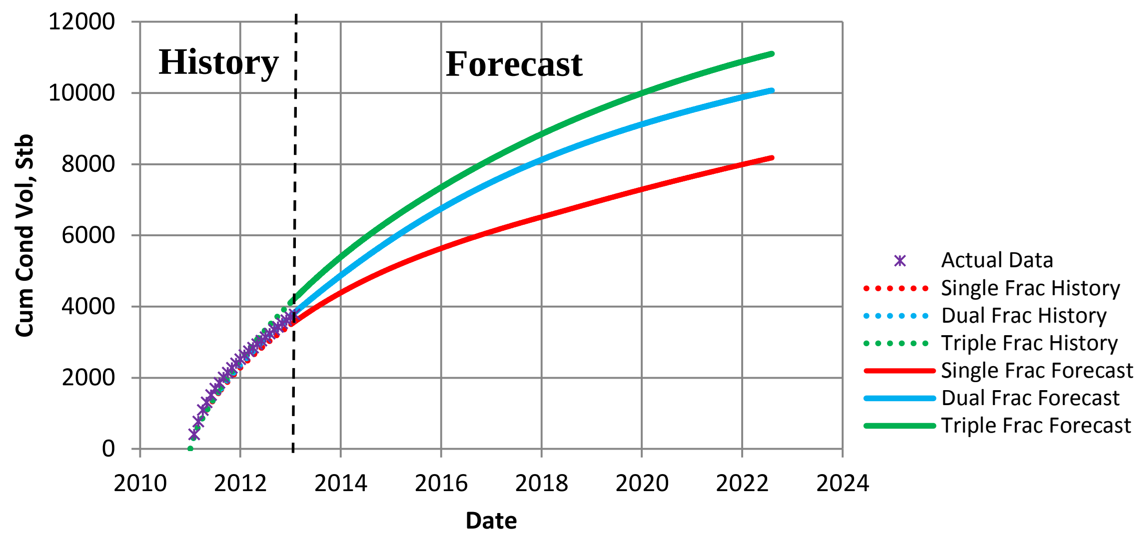
Figure 7 Figure 8 Graphs indicating the quality of history match achieved

History and Forecast for Cumulatives

Cumulative Gas 2011-2023



Cumulative Condensate 2011-2023



CGR 2011-2023

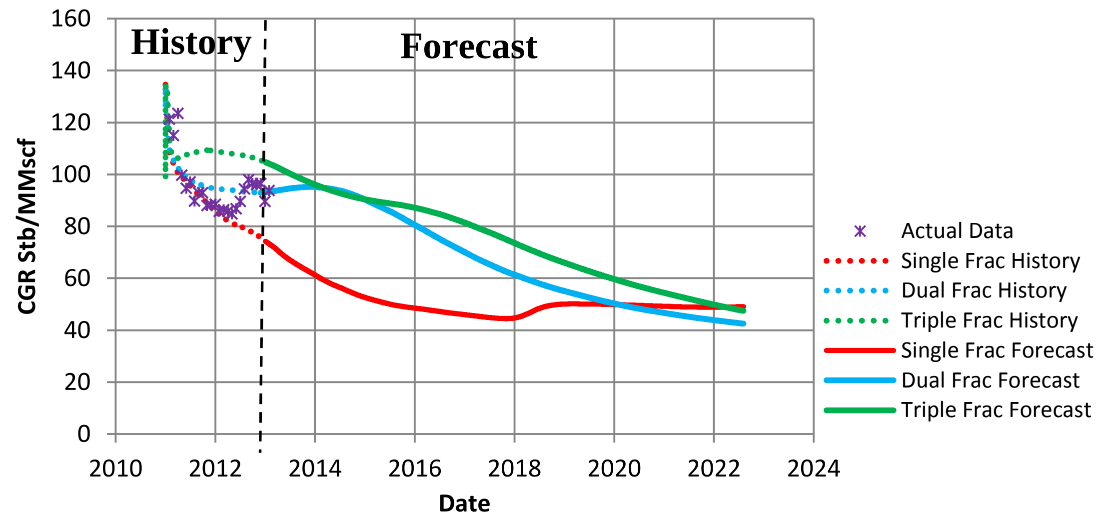


Figure 8 Graphs showing the 10-year forecast results following a 2-year historical production period

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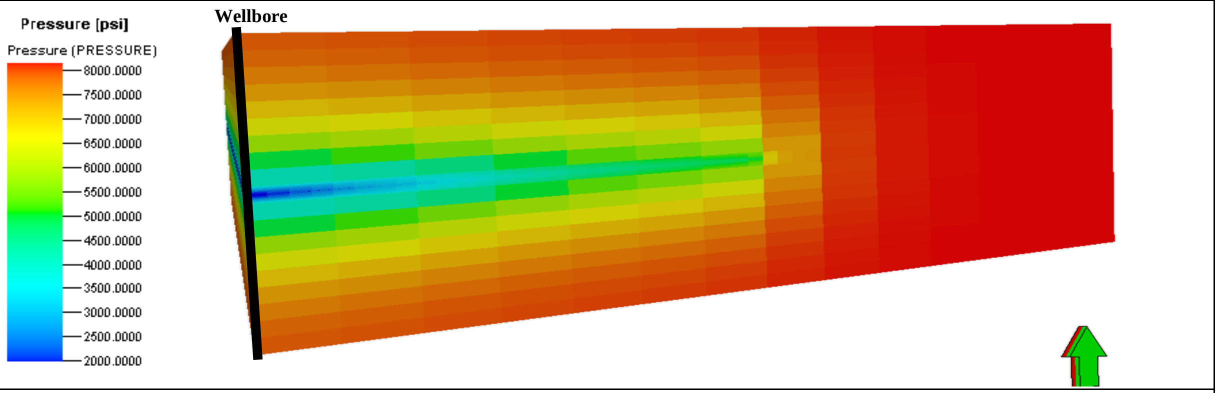
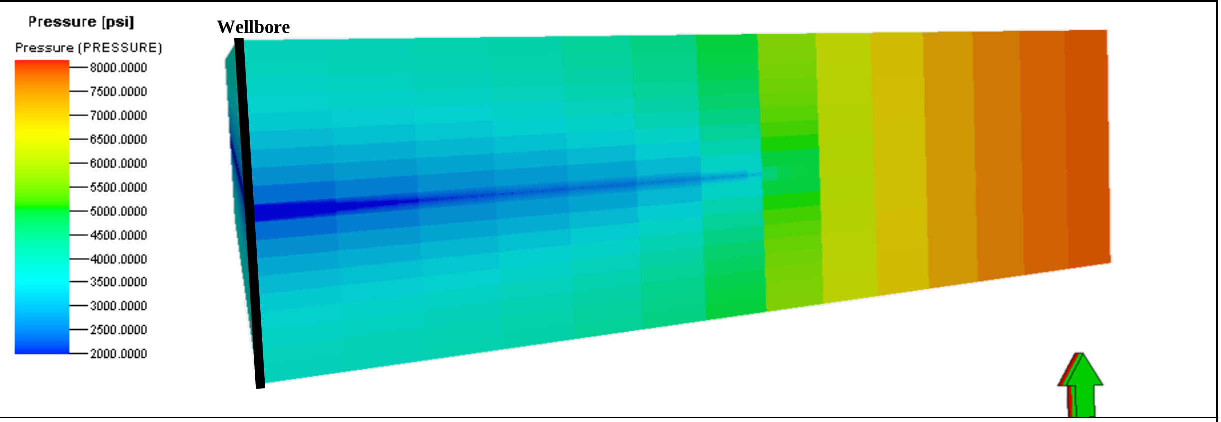
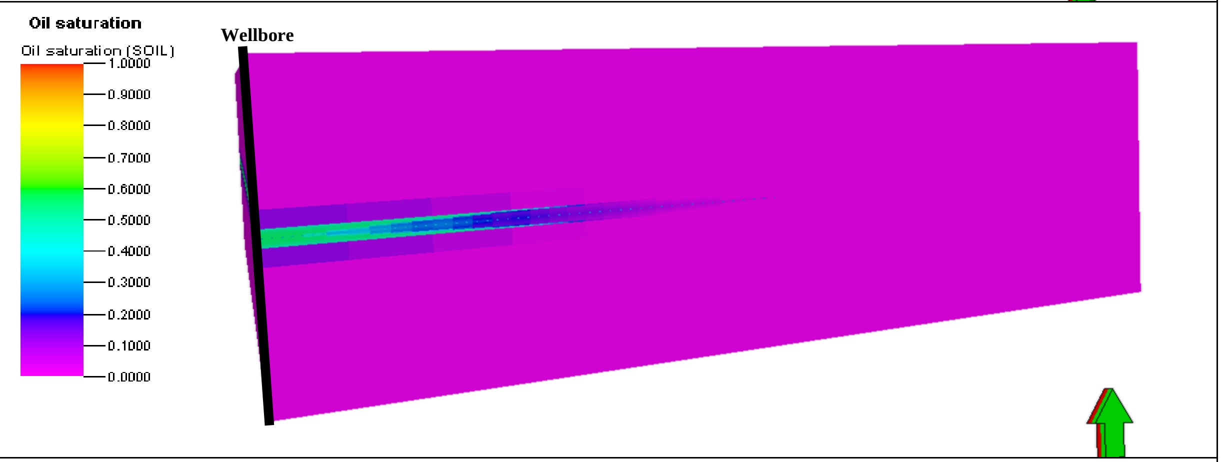
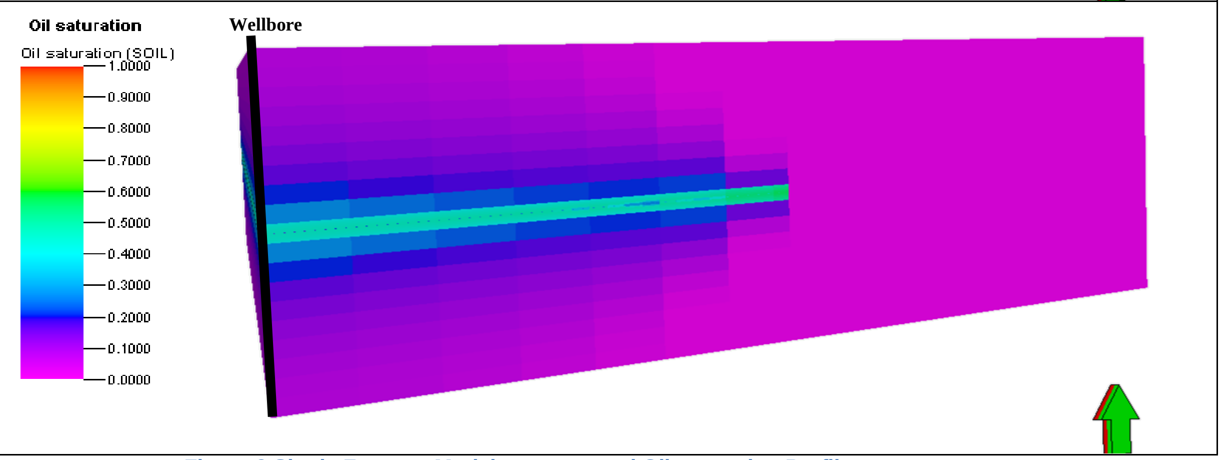
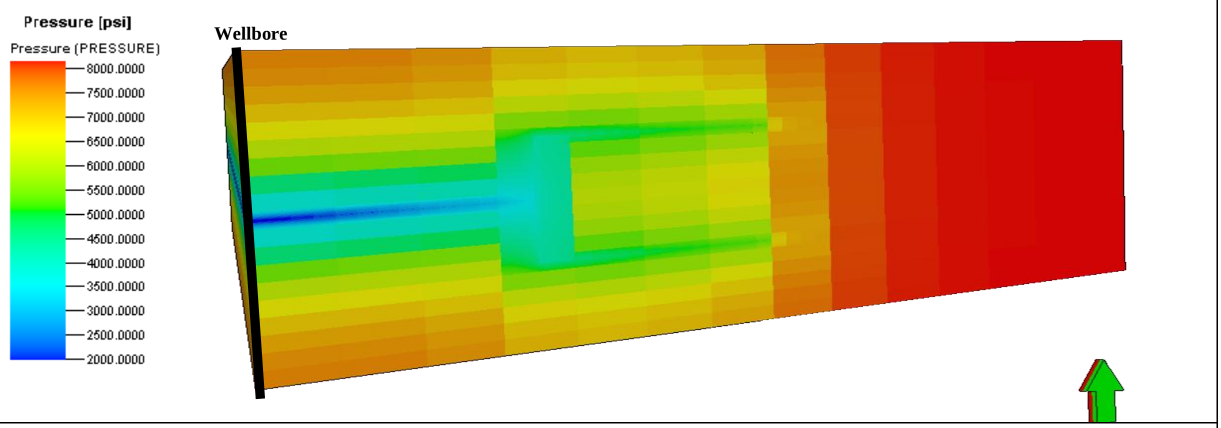
<tr><th colspan="2">Single Fracture Model Results</th></tr>
<tr><td>Pressure Profile @ 2Y</td><td>
</td></tr>
<tr><td>Pressure Profile @10Y</td><td>
</td></tr>
<tr><td>Oil Sat Profile @ 2Y</td><td>
</td></tr>
<tr><td>Oil Sat Profile @ 10Y</td><td>
</td></tr>
</table>

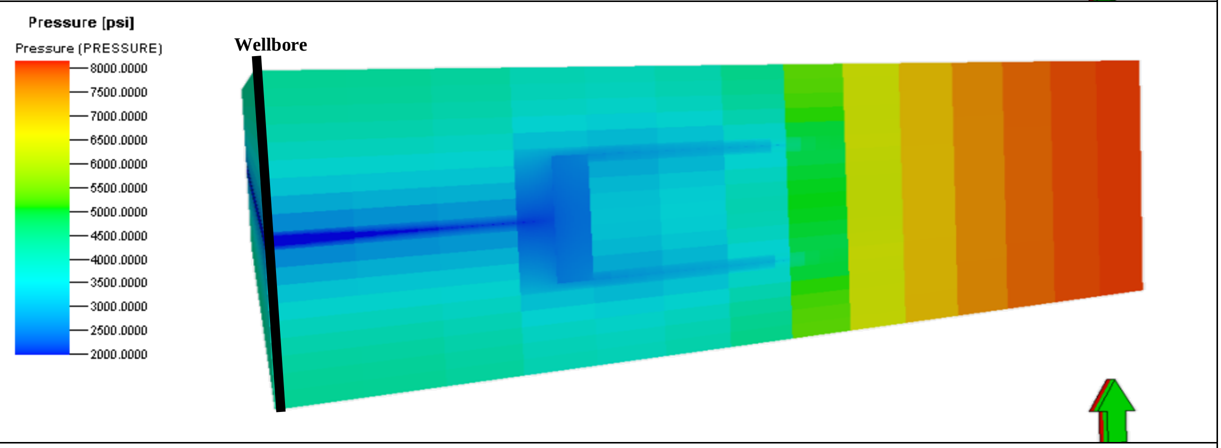
Figure 9 Single Fracture Model pressure and Oil saturation Profiles

Dual Fracture Model Results

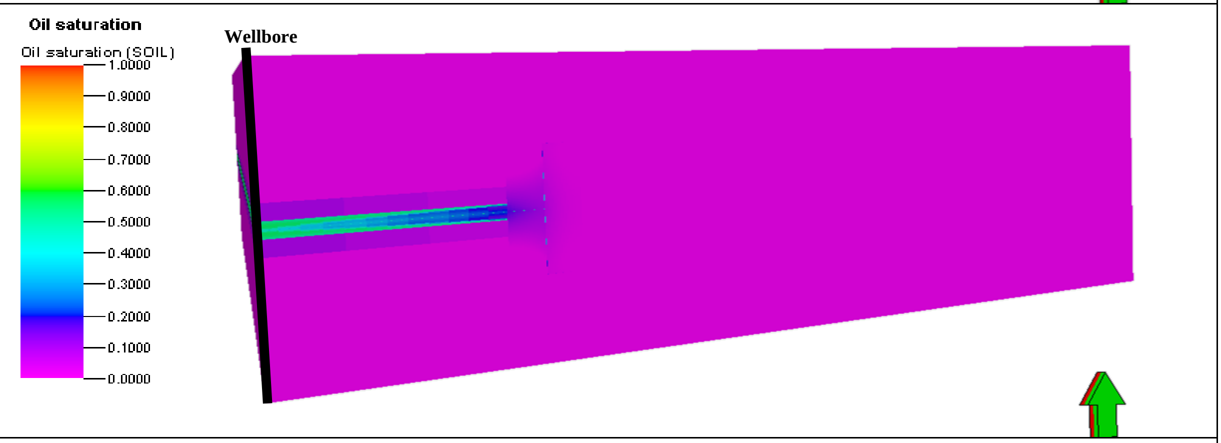
Pressure Profile @ 2Y



Pressure Profile @10Y



Oil Sat Profile @ 2Y



Oil Sat Profile @ 10Y

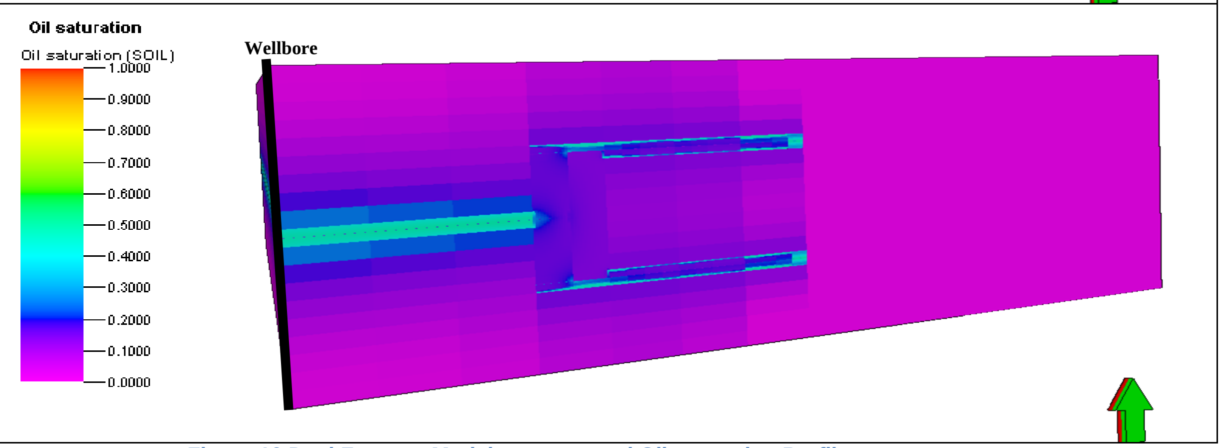
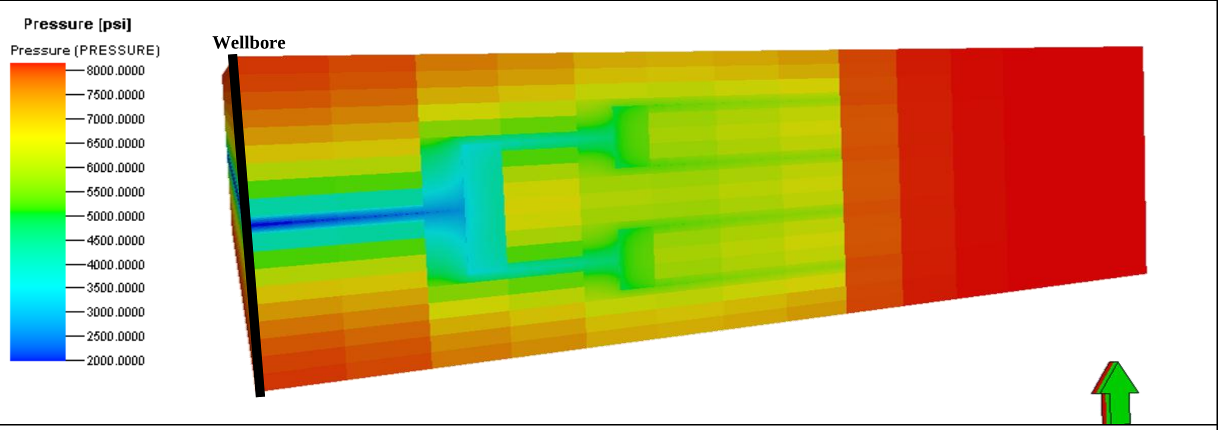


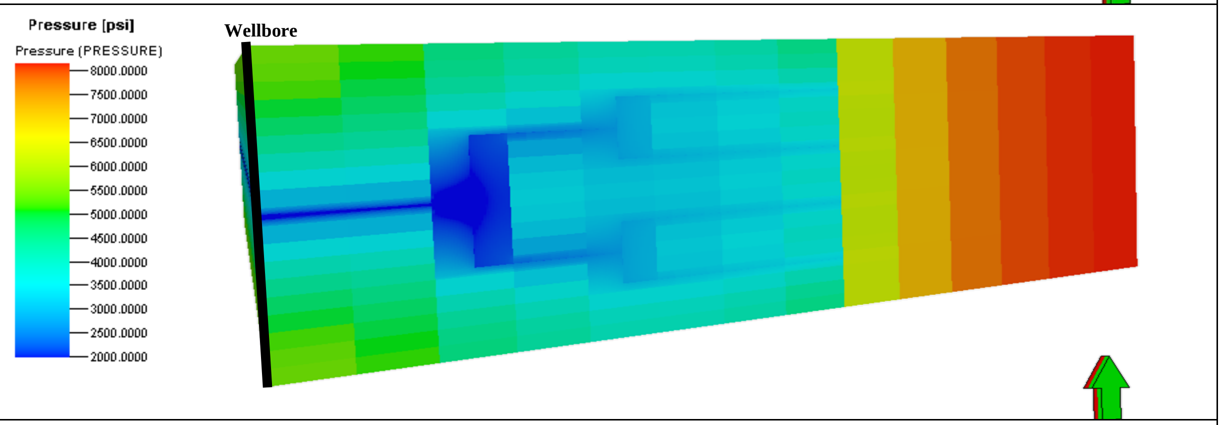
Figure 10 Dual Fracture Model pressure and Oil saturation Profiles

Triple Fracture Model Results

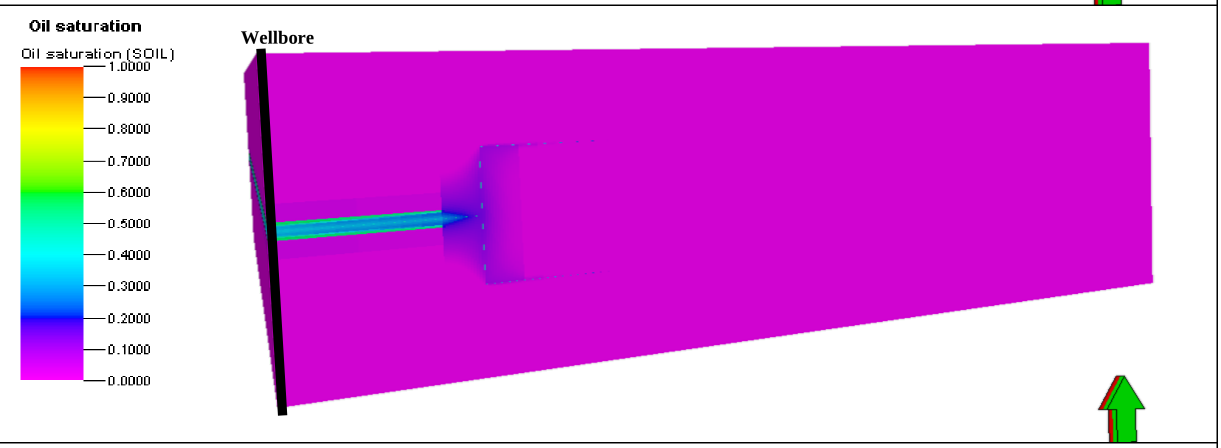
Pressure Profile @ 2Y



Pressure Profile @10Y



Oil Sat Profile @ 2Y



Oil Sat Profile @ 10Y

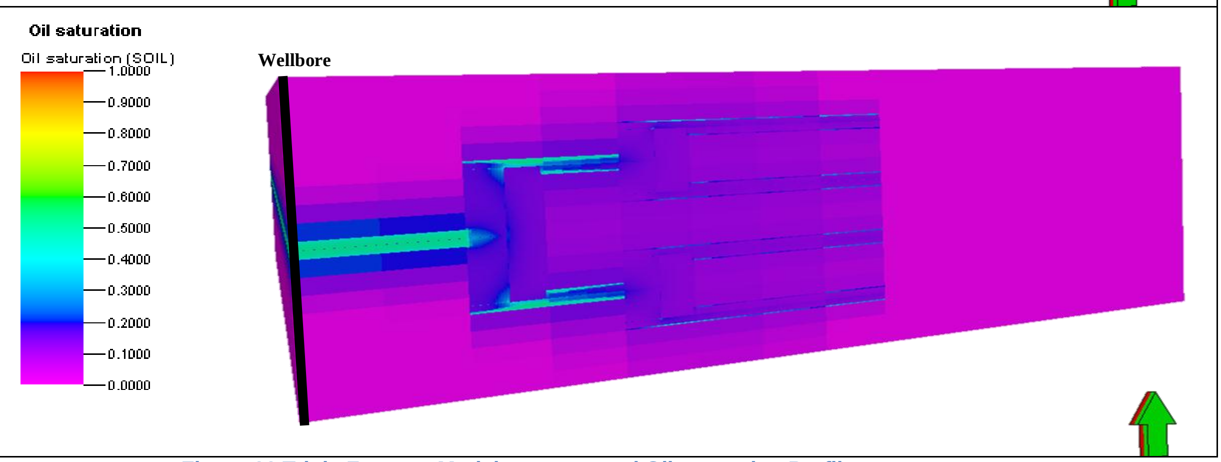


Figure 11 Triple Fracture Model pressure and Oil saturation Profiles

Discussion

The initial gas flow rate of 111Mscf/d was matched for all three alternative fracture geometry cases as illustrated by Figure 7; however, the late time gas rate was consistently over-predicted and remained within the range of 35-38Mscf/d, which is 15-25% higher compared to the observed rate of 30Mscf/d.

Further improvement of history match can be achieved by introducing the following elements into the model, which would reduce the late time gas flow rate:

- Fracture conductivity should be expected to decrease in time due to partial fracture closure following reservoir pressure decline. Daneshy (Daneshy, 2007) was amongst many workers to point out that pressure depletion might lead to reduction in overall conductivity along the fracture over the lifetime of a well.
- Non-Darcy flow effects may impact the performance of a hydraulically fractured well. Many published papers described the reduction in well productivity by lowering the apparent fracture half length. While this effect is more pronounced at high gas (and oil) rates, Miskimins *et al.* (Miskimins & Lopez-Hernandez, 2005) showed that non-Darcy flow effects could impact performance at low flow rates in all wells, and when combined with multiphase flow, the resulting impact on production would be even more drastic. Miskiminis et al. quantified the reductions in flow capacity between 5-30% for a single phase flow.
- Multiphase flow conditions may adversely affect the permeability to gas within a hydraulic fracture, particularly if the possibility of liquid accumulation is accounted for. The magnitude of the reduction might be quantified by consider a hypothetical case with 5% reduction in gas saturation within the fracture at the late production period, which would translate into an almost 20% decrease of the gas permeability, as illustrated by Figure A- 3.
- Fracture branches bonding due to pressure drop around the fracture segement may stop production from some of the fracture segments and thus reduce the overall well productivity.

Figure 7 also shows that the condensate flow rate was over-estimated in all three simulation scenarios at late production times, which was the consequence of having higher than observed gas rates in the model. It should be noted that the observed CGR trend was generally matched, and the Dual and Triple fracture models showed far better CGR trend match when compared to the Single Fracture case. For the latter, simulation model predicted continuous decline after the first year, whereas for the former two clear signs of stabilization were present which are some what consistent with the observed trend (Figure 7).

The forecasted CGR for the Dual and Triple models predicted smooth decline over the 10 year period whereas the Single fracture model showed an abrupt decrease to a minimum by 2018 followed by a slight increase and later stabilization (Figure 8).

Although all three geometries forecasted the same cumulative gas recovery by 2023, larger condensate production was predicted by the Dual and Triple fracture models, which is also illustrated by Figure 8. This result is consistent with the fractal numerical analysis which suggested that a larger area would be drained by a more complex and spatially distributed fracture system. Higher condensate production from the Dual and Triple fracture models can otherwise be explained by more uniform pressure depletion and less pronounced condensate banking around the conductive fracture segments due to smaller in-situ losses.

Summary/Conclusion

Numerical simulation showed that a ‘branched fractal’ models are more effective in describing pressure depletion and gas condensate production for the Duvernay well studied here compared to the traditional single-slab fracture approach. The fractal models allowed for using more realistic shale permeability values in order to reproduce the actual gas rates over a two year historical production period and, more importantly, gave an improved match for the observed CGR trend.

The Dual and Triple fracture models predicted higher condensate recovery over a 10-year forecast period for the same cumulative gas production due to a smaller condensate drop-out losses in the reservoir. This may be in turn due to a more uniform pressure depletion in the drainage area

The proposed modeling approach may be useful for various aspects of the future well design. Firstly, it may assist in estimating the maximum reservoir area accessible (drained) by each fracture segment, thus providing information for selecting best fracture spacing for new wells once historical performance of existing producers has been analyzed. Secondly, it provides valuable insight into reservoir performance at late production times for alternative fracture geometries and appears very promising for optimizing hydraulic fracture design and screening various available technologies for stimulation to create the neccessary geometry in order to maximize liquids recovery from a gas condensate shale reservoir.

Recommendations for further work

In order to check the validity of the 'branched fractal' approach, it is recommended that the following work is carried out:

- Applying the presented technique to a larger number of type wells from various shales;
- Using longer historical data to improve model calibration;
- Using more complex 'branched fractal' geometries by modeling the Quadruple and Quintuple Fractals designed in the numerical design;
- Screening alternative fracture designs to check whether alternative geometry results in better matches and higher condensate recoveries;
- Accounting for the reduction in fracture conductivity with time by incorporating transmissibility as a function of pressure in the model;
- Using pressure data as a history matching parameter to ensure that the well productivity index is better matched;
- Using experimental data (when available) to generate relative permeability curves for the fractures as current data is based on a straight line;

Nomenclature

2D	*Two-dimensional*	*MStb*	*Thousand standard barrels*
3D	*Three-dimensional*	*MMStb*	*Million standard barrels*
µD	*Micro-darcies (E-06)*	*Mscf*	*Thousand standard cubic feet*
#	*Number*	*Mscf/d*	*Thousand standard cubic feet per day*
π	*Pi – mathematical constant (3.14159)*	*MMscf*	*Million standard cubic feet*
A	*Area*	*N*	*Number of iterations*
$A_{\#1},A_{\#2...}A_N$	*Area of iteration 1, 2…,*	*Ny*	*Number of cells in y-direction*
N	*Number*	*Nx*	*Number of cells in x-direction*
Bcf	*Billion cubic feet*	*Nz*	*Number of cells in z-direction*
Bbl	*Barrel*	*Psi/ft*	*Pound per square inch per foot*
Bbl/d	*Barrels per day*	*Psi*	*Pound per square inch*
Bbbl/MMscf	*Barrel per million standard cubic feet*	*R*	*Radius*
CGR	*Condensate-gas ratio*	*SRV*	*Stimulated reservoir volume*
CSUG	*Canadian Society for Unconventionals*	*SGPM*	*Shale gas predictive model*
D	*Darcy*	*Tcf*	*Trillion cubic feet*
DFN	*Discrete fracture network*	*UF*	*Unstructured fracture*
EU	*European Union*	*US*	*United States*
Ft	*Feet*	$V_{\#1},V_{\#2...}V_N$	*Volume of iteration number 1, 2…, N*
LGR	*Local grid refinement*	$W_{\#1},W_{\#2...}W_N$	*Width of branches from iteration 1, 2…,*
L	*Length*	x_f	*Half fracture length*
Lb/ft^3	*Pounds per cubic feet*	*Mcf/d*	*Thousand cubic feet per day*

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Appendices

Appendix A: Milestones in the study of Natural and Hydraulic Fractures

SPE Paper n°	Year	Title	Author(s)	Contribution
17607	1988	"Fracture Design Considerations in Naturally Fractured Reservoirs"	C.L. Cipolla, P.T. Branagan, and S.J. Lee	First to investigate natural fracture/matrix properties and compare productivity of naturally fractured reservoirs with homogeneous reservoirs of the same average flow capacity.
77440	2002	"Microseismic Imaging of Hydraulic Fracture Complexity in the Barnett Shale"	S.C Maxwell, Urbancic, N. Steinsberger, and R. Zinno	First to note the intersection of stimulations with pre-existing fractures. Also related differences in production rates from various wells to fracture geometry.
90051	2004	"Optimizing Horizontal Completion Techniques in the Barnett Shale Using Microseismic Fracture Mapping"	M. K. Fisher, J.R. Heinze, C.D. Harris, B.M. Davidson, C.A. Wright, and K.P. Dunn	Compared production results from various treatment designs and correlated microseismic-fracture-mapping results to the stimulated reservoir volume and the overall reservoir production.
102103	2006	"Integration of Microseismic Fracture Mapping Results With Numerical Fracture Network Production Modeling in the Barnett Shale"	M.J. Mayerhofer, E.P. Lolon, J.E. Youngblood, and J.R. Heinze	Showed that reservoir performance is associated with fracture geometry and fractures act as very long permeable condits for fluid flow in a low permeability matrix.
115769	2008	"The Relationship Between Fracture Complexity, Reservoir Properties, and Fracture Treatment Design"	C.L. Cipolla, N. R. Warpinski, M.J. Mayerhofer, E.P. Lolon, and M.C. Vincent	Associates fracture complexity with proppant distribution and discuss its effect on gas well performance.
124884	2009	"Numerical Modeling of Multi-Stranded Hydraulic Fracture Propagation: Accounting for the Interaction Between Induced and Natural Fractures"	Arash Dahi-Taleghani, and Jon E. Olson	Studied the interactions between pre-existing natural fractures and advancing hydraulic fractures and found that they are key in leading to complex fracture patterns.
125530	2009	"Reservoir Modeling in Shale-Gas Reservoir"	C.L. Cipolla, E.P. Lolon, J.C. Erdle, and B. Rubin	Proposed the application of LGR to model the highly nonlinear complex fracture network
146376	2011	"Optimizing Transverse Fractures in Liquid-Rich Formations"	M. C. Vincent	Discusses the transverse fractures and highlights the complications in liquids-rich formations.
Oklahoma University Thesis	2012	"Investigating Drainage Patterns of Shale Production as a Function of Type Of Fracture System In The Reservoir"	Adebusola B. Odunuga	Investigates drainage patterns and their effect on production trends using fractals to model complex fracture systems in shale gas reservoirs.

Table A- 1 Milestones

Appendix B: Critical Literature Review

SPE 17607 (1988)

"Fracture Design Considerations in Naturally Fractured Reservoirs"

Authors: C.L. Cipolla, P.T. Branagan, and S.J. Lee

Contribution to the description of fracture geometry and forecasting 2-phase production and recoveries in rich gas condensate shale reservoirs:
This paper examined the feasibility of applying accepted hydraulic fracture design criteria for homogeneous reservoirs to naturally fractured reservoirs. It also compared post-fracture well productivity for naturally fractured wells to that of analogous homogeneous reservoir. And finally, it illustrated the effects of permeability impairment to the natural fractures intersected by a hydraulic fracture.

Objective of the paper:
To investigate a variety of natural fracture/matrix properties and compare the productivity of a naturally fractured reservoir to homogeneous reservoirs with same average flow capacity.

Methodology used:
Integration of general reservoir simulation results with actual field data from naturally fractured reservoirs in the Piceance Basin in Colorado.

Conclusion reached:

- Post-fracture well performance, optimum fracture lengths and conductivity for isotropic naturally fractured reservoirs can be predicted using fracture design criteria applied to homogeneous reservoirs.
- Fracture design and interpretation of post-fracture well test data may be affected by the anisotropy of natural fractures. Optimum fracture lengths in an anisotropic naturally fractured reservoir maybe shorter than that in an isotropic naturally fractured reservoir with both having similar average flow capacity and assuming non changing hydraulic fracture conductivity with the hydraulic fracture parallel to the natural fractures with the maximum permeability.
- Isotropic naturally fractured reservoir will have higher post-fracture well productivity and present net value profit when compared to an anisotropic naturally fractured reservoir, assuming parallel hydraulic fracture orientation to the natural fractures.
- Post-fracture well productivity can be significantly reduced as a result of natural fracture permeability impairment which should be accounted for and minimized as much as possible.

Comments:
Comparisons were based on homogeneous and naturally fractured reservoirs with identical average/bulk reservoir permabilities.

SPE 77440 (2002)

"Microseismic Imaging of Hydraulic Fracture Complexity in the Barnett Shale"

Authors: S.C Maxwell, T.I. Urbancic, N. Steinsberger, and R. Zinno

Contribution to the description of fracture geometry and forecasting 2-phase production and recoveries in rich gas condensate shale reservoirs:
This paper associated the existence of a large fracture network with stimulation treatments and noted that interactions are present between the induced hydraulic fractures and the pre-existing natural fracture network.

Objective of the paper:
To investigate the complexity of fracture growth during well stimulation in the naturally fractured Barnett Shale play in Texas.

Methodology used:
Advanced Seismic Processing

Conclusion reached:
- Simulation built using microseismic imaging data from the Barnett Shale indicated the intersection of hydraulic fractures with pre-existing fracture networks;
- Significant heterogeneities are found between different wells, which are seemingly controlled by the fracture geometry and the performance of neighboring wells.

Comments:
Author also noted that following a stimulation treatment, generally the fractures are well contained in the target zone, although evidence of growth out-of-zone has been identified.

SPE 90051 (2004)

"Optimizing Horizontal Completion Techniques in the Barnett Shale Using Microseismic Fracture Mapping"

Authors: M. K. Fisher, J.R. Heinze, C.D. Harris, B.M. Davidson, C.A. Wright, and K.P. Dunn

Contribution to the description of fracture geometry and forecasting 2-phase production and recoveries in rich gas condensate shale reservoirs:
This paper compared production results from various treatment designs and correlated microseismic-fracture-mapping results to the stimulated reservoir volume and the overall reservoir production. This was done for the first twenty three horizontal wells in the same general 'Core' area of the Fort Worth Basin. Author also discussed drilling and completion strategies, studies the fracture network areas obtained from each, and then compared the fracture effectiveness with the standard procedure used in vertical Barnett wells.

Objective of the paper:
Study aimed at understanding created fracture geometry for various completion designs.

Methodology used:
Analysis of microseismic imaging data and diagnostic plots.

Conclusion reached:
- Location of the perforation clusters has little or no effect on fracture location.
- Hydraulic fractures showed clear interactions with the existing natural fracture systems.
- Larger fracture fluid volumes do not necessarily increase network length and well productivity in horizontal wells.

Comments:
Author also draws several other conclusions related to completion design and fracture treatment stages which are not relevant to this study. This study clearly indicated interactions between natural and induced fractures suggesting that they cannot be modeled as two separate permeable networks.

SPE 102103 (2006)

"Integration of Microseismic Fracture Mapping Results With Numerical Fracture Network Production Modeling in the Barnett Shale"

Authors: M.J. Mayerhofer, E.P. Lolon, J.E. Youngblood, and J.R. Heinze

Contribution to the description of fracture geometry and forecasting 2-phase production and recoveries in rich gas condensate shale reservoirs:
Paper illustrates how different fracture network characteristics impact well performance and proved that induced fractures act as a network of very long permeable conduits in a tight matrix. It also demonstrates how microseismic mapping results can be integrated with production modeling to provide a new tool for well design.

Objective of the paper:
To present an approach of coupling microseismic fracture mapping with numerical production modeling of fracture networks based on a case study in the Barnett Shale.

Methodology used:
Analysis of microseismic imaging and pressure buildup test data.

Conclusion reached:

- A discrete number of fracture segments which resemble the areal magnitude of the microseismic fracture imagine can be used for production modeling;
- Additional data including multi-well production simulations would be required in order to estimate the position, ratio of effective network width to length, and fracture spacing.
- Well performance is associated with fracture size and SRV, the larger the fracture, the higher the SRV and thus the better the performance.
- As the fracture network size exceeds a threshold value, the relative benefits of size are lost due to the low fracture conductivity.
- No fluid is drained from the shale matrix due to its sub-micrpdarcy permeability.
- Fracture spacing within the overall fracture network structure will have an impact on production in low permeability shale.
- Fracture staging along a horizontal well can lead to production loss (roughly proportional to the percentage of the unstimulated lateral).
- Production benefits can be gained from increasing the near well conductivity however if pumping schedules become too high then it may result in a decrease of the overall network size.

Comments:
Study based on Barnett Shale data however the conclusions drawn about are applicable to all shale/tight formations.

SPE 115769 (2008)

"The Relationship Between Fracture Complexity, Reservoir Properties, and Fracture Treatment Design"

Authors: C.L. Cipolla, N. R. Warpinski, M.J. Mayerhofer, E.P. Lolon, and M.C. Vincent

Contribution to the description of fracture geometry and forecasting 2-phase production and recoveries in rich gas condensate shale reservoirs:

Paper looked at different scenarios of complex fracture growth and associated natural fracture and hydraulic fracture interactions with well performance.

Objective of the paper:

To investigate fracture treatment design issues as they relate to various degrees and types if fracture complexity. Also investigates the effect of fracture fluid viscosity on fracture complexity, proppant distribution in complex fractures, and fracture conductivity requirements for complex fractures.

Methodology used:

Evaluation of microseismic fracture mapping data and Reservoir simulation.

Conclusion reached:

- Injected fluid viscosity can affect the fracture complexity. Pumping a high viscosity fluid can help reduce fracture growth complexity in reservoirs prone to complex systems;
- Average proppant concentration decreases with fracture complexity increase resulting in lower fracture conductivity;
- Fracture complexity control becomes challenging when Young's modulus decreases below 2E+06 psi, this is caused by the failure to generate sufficient un-propped or partially propped fracture conductivity;
- The application of smaller, higher strength proppant may help in developing moderately complex fracture growth in low permeability reservoirs;
- Significant production enhancement maybe possible by exploiting moderately complex fracture growth (small networks) in tight reservoirs with relatively hard formations;
- Significant production enhancement maybe possible by exploiting very complex fracture growth (large networks) in very tight reservoirs with relatively hard formations;

Comments:

Complex fracture systems are studied by looking at multiple parallel (planar) fracture systems. Paper does not address hydraulic fracture and natural fractures but assumes that the hydraulic fractures are the propped already existing natural fracture systems.

SPE 124884 (2009)

"Numerical Modeling of Multi-Stranded Hydraulic Fracture Propagation: Accounting for the Interaction between Induced and Natural Fractures"

Authors: Arash Dahi-Taleghani, and Jon E. Olson

Contribution to the description of fracture geometry and forecasting 2-phase production and recoveries in rich gas condensate shale reservoirs:

Paper studied interactions between hydraulic and the surrounding natural fractures and the stresses which cause them to communicate and presents a complex hydraulic fracture propagation model based on the Extended Finite Element Method (XFEM)

Objective of the paper:

To investigate the dominant factors governing the diversion or offset of hydraulic fractures in the presence of natural fractures.

Methodology used:

Extended Finite Element Method (XFEM)

Conclusion reached:

- Growing fractures as a result of stimulation causes large tensile and shear stresses ahead of and near the tip, if these stresses are large enough, they may exert a debonding or shearing effect on sealed natural fractures.
- A new extended finite element model (XFEM) was presented to analyze multiple fracture growth by fluid injection, the model couples fluid in the hydraulic fracture with fracture propagation mechanics. Coupling provides an insight into fracture propagation rate.
- The effects of stress anisotropy could magnify the effect of natural fractures on hydraulic fracture propagation.

Comments:

Paper also states that the findings can be used to explain different observed behaviors of hydraulic fracturing in tight gas reservoirs.

SPE 125530 (2009)

“Reservoir Modeling in Shale-Gas Reservoir”

Authors: C.L. Cipolla, E.P. Lolon, J.C. Erdle, and B. Rubin

Contribution to the description of fracture geometry and forecasting 2-phase production and recoveries in rich gas condensate shale reservoirs:

Paper illustrates the application of LGR and numerical reservoir simulation and advanced decline curve analysis to model the issues associated with conventional production data analysis techniques when applied to unconventional reservoirs.

Objective of the paper:

To focus on the impact of gas desorption and stress sensitive network fracture conductivity on well performance, and discuss various shale-gas reservoir simulation approaches.

Methodology used:

Analysis of microseismic mapping data and Reservoir simulation using a case study from the Barnett Shales.

Conclusion reached:

- The effects of stress dependent or low network fracture conductivity can be improved through a fracture design treatment which creates a high relative primary fracture;
- Numerical reservoir simulation history matching can be non-unique in complex shale gas reservoirs. However this can be improved by integrating special core analysis and microseismic data to determine the SRV. Combining this data further with laboratory measurements of un-propped and partially propped fracture conductivity could help improve the insights gained from reservoir simulation;
- The complex fluid flow in shale-gas reservoirs cannot be described using production data analysis (advanced type curve analysis);
- Discrete numerical modeling of the fracture network and tight matrix rock is important to accurately represent production from shale-has reservoirs.

Comments:

Paper has other conclusions which are more specific to the case study and are not deemed relevant to this study.

SPE 146376 (2011)

"Optimizing Transverse Fractures in Liquid-Rich Formations"

Authors: M. C. Vincent

Contribution to the description of fracture geometry and forecasting 2-phase production and recoveries in rich gas condensate shale reservoirs:
This paper discusses the complications associated with flow behavior of liquids-rich formations. It also reviews the literature where these problems were highlighted.

Objective of the paper:
To explain the challenges of accommodating multiple flow in transverse fractures and summarize theoretical, laboratory, and field results demonstrating the best practices.

Methodology used:
Review and analysis of production and well data and outcrops images from the Bakken, Three Forks, Eagle Ford, Viking, Nobrara and Kuparuk - uses diagnostic plots to identify flow regimes, boundary effects and productivity impairment (Fetkovich, Harmonic, cum production).

Conclusion reached:
Liquids rich formations introduce additional pressure losses within the fracture as a result of multiphase flow. This adds to the complexity of varying fracture conductivity and liquids removal from the fracture to the wellbore.

Comments:
Paper draws several other conclusions associated with multiple transverse fractures and fracture treatments which are not directly related to this study and are therefore not listed above.

OKLAHOMA UNIVERSITY THESIS (2012)

“Investigating Drainage Patterns of Shale Production as a Function of Type Of Fracture System In The Reservoir”

Authors: Adebusola B. Odunuga

Contribution to the description of fracture geometry and forecasting 2-phase production and recoveries in rich gas condensate shale reservoirs:

Paper demonstrates the use of fractals to model complex natural fracture systems in shale gas reservoirs. Author also goes on to predict flow performance of gas through the reservoir using the representative fracture system.

Objective of the paper:

To analyze drainage patters and their effect on production trends in shale gas reservoirs involving complex fracture systems.

Methodology used:

Analyzing SEM images, logs and pictures of outcrops and building fracture patterns in Reservoir simulation.

Conclusion reached:

- Highest cumulative production was achieved from superposed orthogonal fracture networks due to their high fracture content and connectivity;
- Little change was observed in reservoir pressure where there is no intersecting fracture network, indicated by slower depletion in the region;
- Well location determines the productivity of the reservoir; strategic well locations can help optimize production in areas where fractal patterns can be used to describe the existing fracture network.

Comments:

This study is very closely associated with this research, uses fractal pattern networks to model naturally existing fractured systems. This study uses single fractals to model hydraulically induced fracture in a naturally fractures reservoir.

Appendix C: Numerical Design Results

3D Area & Width Calculations for Constant Total Volume

iteration #	1	2	3	4	5
Width	1	0.408	0.215	0.112	0.059
Fracture half-length	10	10	10	10	10
W_N/W_1	**1.00**	**0.41**	**0.22**	**0.11**	**0.06**
L1	10	5.00	3.33	2.50	2.00
L2		5.00	3.33	2.50	2.00
H2 Spacing		3.33	3.33	3.33	3.33
L3			3.33	2.50	2.00
H3 Spacing			1.67	1.67	1.67
L4				2.50	2.00
H4 Spacing				0.83	0.83
L5					2.00
H5 Spacing					0.42
Check total length	10.00	10.00	10.00	10.00	10.00
Total spacing	0.00	3.33	3.33	3.33	3.33
Total length of branches	**10.00**	**13.33**	**30.00**	**47.50**	**75.33**
A1	314.16	78.54	34.91	19.63	12.57
A2		471.24	209.44	117.81	75.40
A2 Spacing		104.72	69.81	52.36	41.89
A3			698.13	392.70	251.33
A3 Spacing			69.81	52.36	41.89
A4				1099.56	703.72
A4 Spacing				52.36	41.89
A5					1809.56
A5 Spacing					41.89
Total Area	**314.16**	**654.50**	**1082.10**	**1786.78**	**3020.12**
A_N/A_1	**1.00**	**2.08**	**3.44**	**5.69**	**9.61**
V1	314.16	78.54	34.91	19.63	12.57
V2		192.27	85.45	48.07	30.76
V2 Spacing		42.73	28.48	21.36	17.09
V3			150.10	84.43	54.04
V3 Spacing			15.01	11.26	9.01
V4				123.15	78.82
V4 Spacing				5.86	2.47
V5					106.76
V5 Spacing					2.47
Total Volume	**314**	**314**	**314**	**314**	**314**

Table A- 2 Area & width calculations

Constant total contacted volume was assumed based on volume of proppant injected. Using this assumption, functions were generated for the reduction in width with increased number of iterations. The 3D area of the first iteration was simply calculated by using the area of a circle given in equation (1) where R is the fracture half-length.

$$A_{\#1} = \pi R^2 \quad (1)$$

However, the area was slightly more complex for iterations 2 to 5, this was estimated by calculating the area of each fracture stage in addition to the area of the vertical spacing section between the branches. For iteration #2, this was done using equation (2).

$$A_{\#2} = \pi r_1 1^2 + 2\pi(R^2 - r_1 2^2) + 2\pi r_2 h2 \quad (2)$$

Where;
r1 = length of the first fracture stage in iteration #2;
r2 = length of the second fracture stage in iteration #2;
h2 = height of spacing between the two branches of the second fracture stage in iteration #2.

Finally the volume for each iteration was calculated using equation (3) where W is the width corresponding to each fracture stage;

$$V_N = A_{\#1}W_1 + A_{\#2}W_2 \ldots . A_{\#N}W_N \quad (3)$$

The total stimulated volume was kept constant for all iterations and therefore the width and area was estimated based on;

$$V_{\#1} = V_{\#2} = V_{\#3} = V_{\#4} = V_{\#5} = V_N \quad (4)$$

Appendix D: MatLab Code

```
% Initial Fracture iteration 1: Single Plane
x1 =[ 0 6];
y1= [2;2];
plot(x1,y1)

% Iteration 2: Dual Fracture
x1= [ 0 3];      % iteration 1

x2= [ 3 3 6];
y2= [2;3;3];      %branch 1
t2= [2;1;1];     %branch 2
plot(x1,y1, x2, y2, x2,t2)

% Iteration 3: Triple Fracture
x12= [0 2 2 4];
y12= [2;2;3;3];
z12= [2 2 4];
 t12=[2;1;1];  % iteration 1+ 2

x3= [4 4 6];     %iteration 3

y31= [3;3.5;3.5];
 t31=[ 3;2.5;2.5];  %branch 1
y32= [1;1.5;1.5];  % branch 2
t32= [1;0.5;0.5];
plot(x12, y12, z12, t12, x3, y31, x3, t31, x3, y32, x3, t32)

% Iteration 4: Quadruple Fracture
x12= [0 1.5 1.5 3];
z12= [1.5 1.5 3];         %iterations 1+2

x3= [3 3 4.5];  %iteration 3

x4= [4.5 4.5 6];          % iteration 4

y41= [3.5;3.75;3.75];
t41= [3.5;3.25;3.25];   %branch 1
y42= [2.5;2.75;2.75];
t42= [2.5;2.25;2.25];   %branch 2
y43= [1.5;1.75;1.75];
t43= [1.5;1.25;1.25];   %branch 3
 y44= [0.5;0.75;0.75];
t44= [0.5;0.25;0.25];   %branch4
plot(x12, y12, z12, t12, x3, y31, x3, t31, x3, y32, x3, t32, x4, y41, x4, t41,
x4,y42,x4,t42,x4,y43,x4,t43,x4,y44,x4,t44)


% Iteration 5: Quintuple Fracture
```

```
x12= [ 0 1.2 1.2 2.4];
z12=[1.2 1.2 2.4];      % iteration 1+2

x3= [2.4 2.4 3.6];      % iteration 3

x4= [3.6 3.6 4.8];      % iteration 4

x5= [4.8 4.8 6];                % iteration 5

y51= [3.75;3.875;3.875];
t51= [3.75;3.625;3.625];        % Branch 1
y52= [3.25;3.375;3.375];
t52= [3.25;3.125;3.125];        % Branch 2:
y53= [2.75;2.875;2.875];
t53= [2.75;2.625;2.625];        % Branch 3
y54= [2.25;2.375;2.375];
 t54= [2.25;2.125;2.125];       % Branch 4
y55= [1.75;1.875;1.875];
t55= [1.75;1.625;1.625];        % Branch 5
y56= [1.25;1.375;1.375];
t56= [1.25;1.125;1.125];        % Branch 6
y57= [0.75;0.875;0.875];
 t57= [0.75;0.625;0.625];       % Branch 7
y58= [0.25;0.375;0.375];
t58= [0.25;0.125;0.125];        % Branch 8
plot(x12, y12, z12, t12, x3, y31, x3, t31, x3, y32, x3, t32, x4, y41, x4, t41,
x4,y42,x4,t42,x4,y43,x4,t43,x4,y44,x4,t44,x5,y51,x5,t51,x5,y52,x5,t52,x5,y53,x5,t53,x5,y54,x5,t54,x5,y
55,x5,t55,x5,y56,x5,t56,x5,y57,x5,t57,x5,y58,x5,t58)
```

Appendix E: Eclipse Grid Design & Input Data

Dead Oil Properties

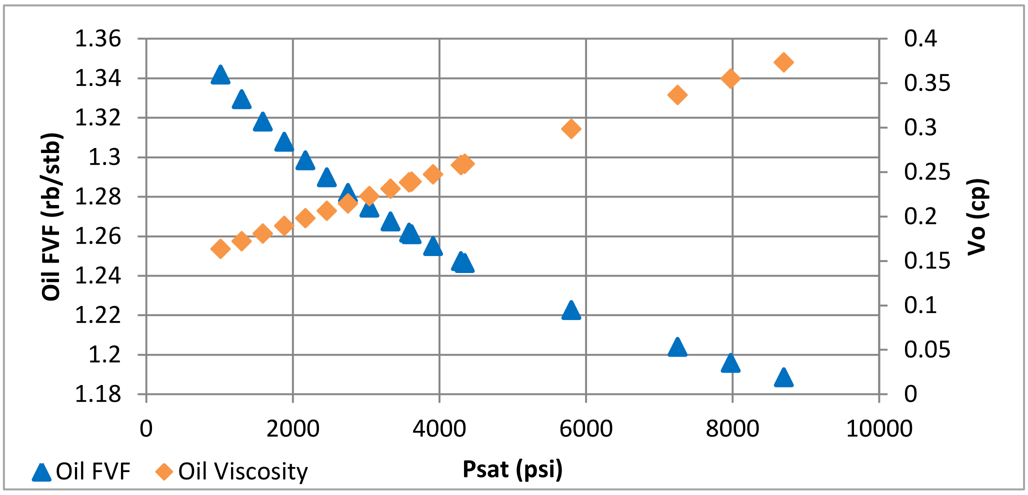

Figure A- 1 Oil FVF & viscosity

Relative Permeability Data

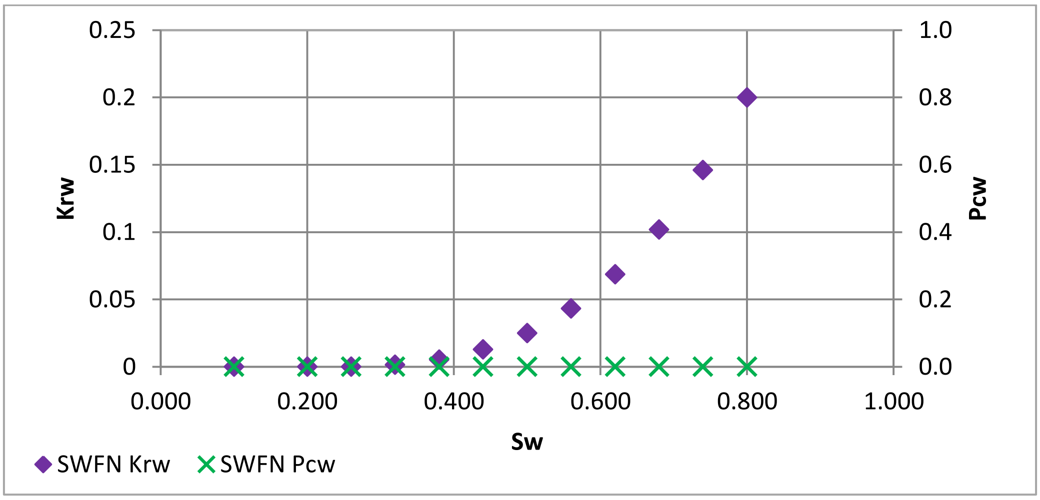

Figure A- 2 Water relative permeability data

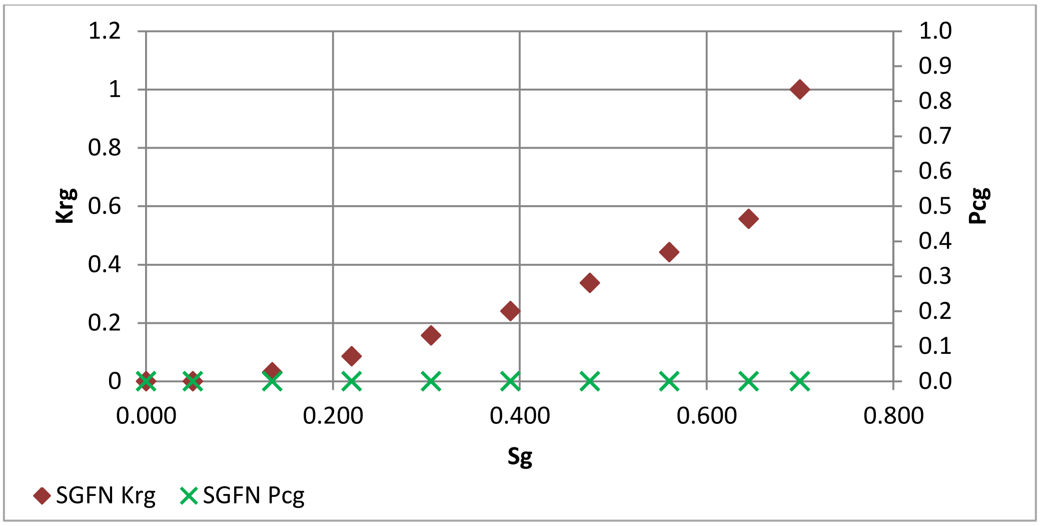

Figure A- 3 Gas relative permeability data

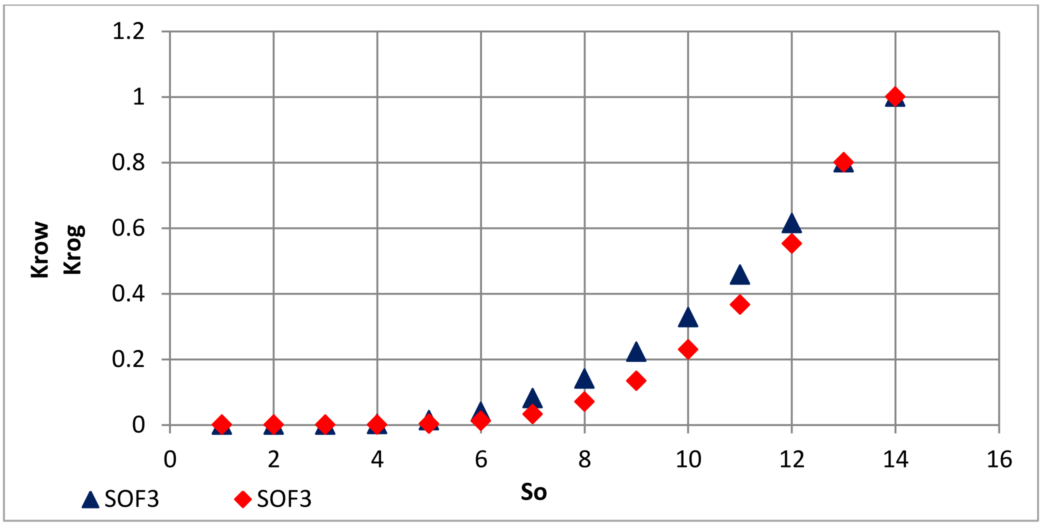

Figure A- 4 3-phase relative permeability data

Fracture Properties

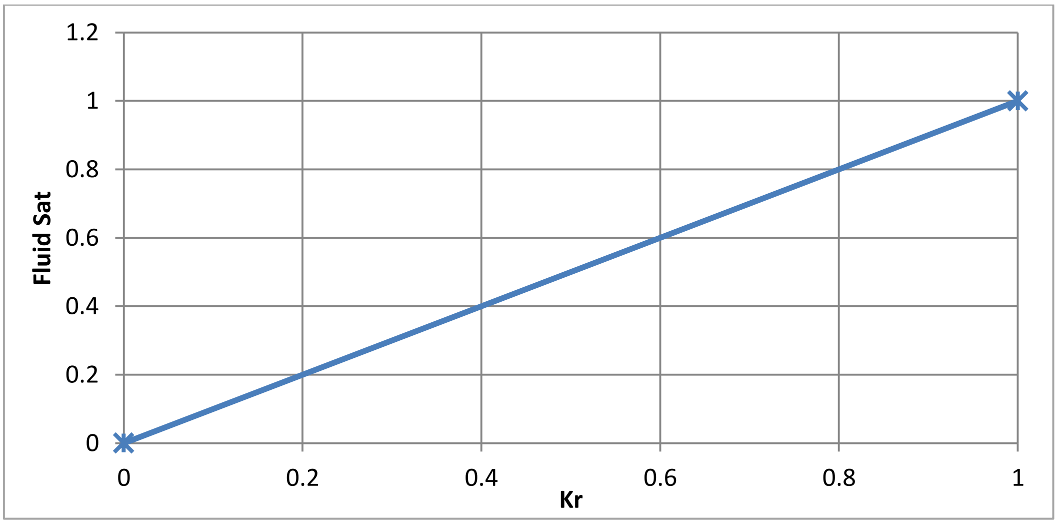

Figure A- 5 Fracture Relative Permeability

Rich Gas Properties

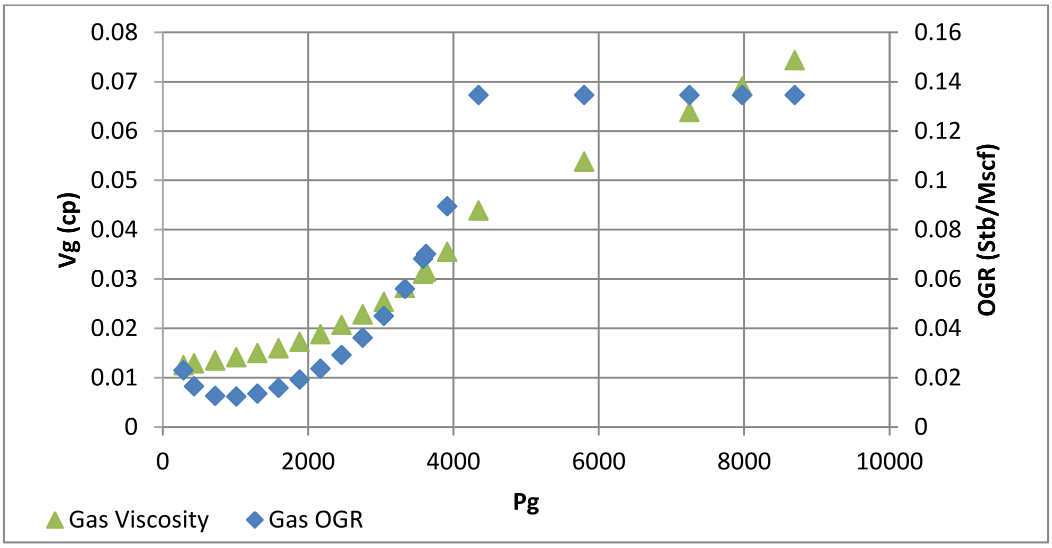

Figure A- 6 Gas OGR & viscosity

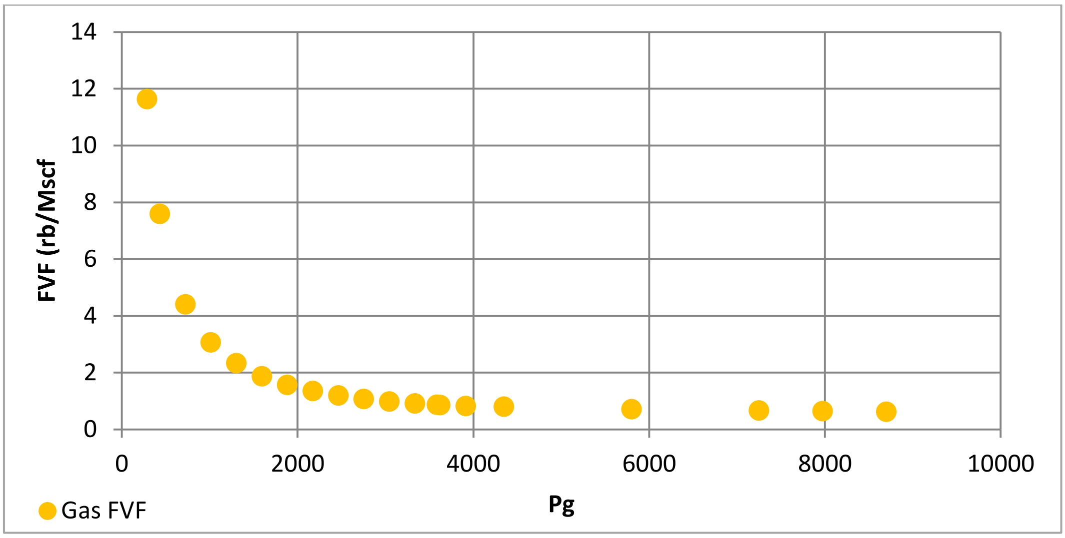

Figure A- 7 Gas FVF

Appendix F: Trilogy's Production Data – Analyzed for half fracture segments

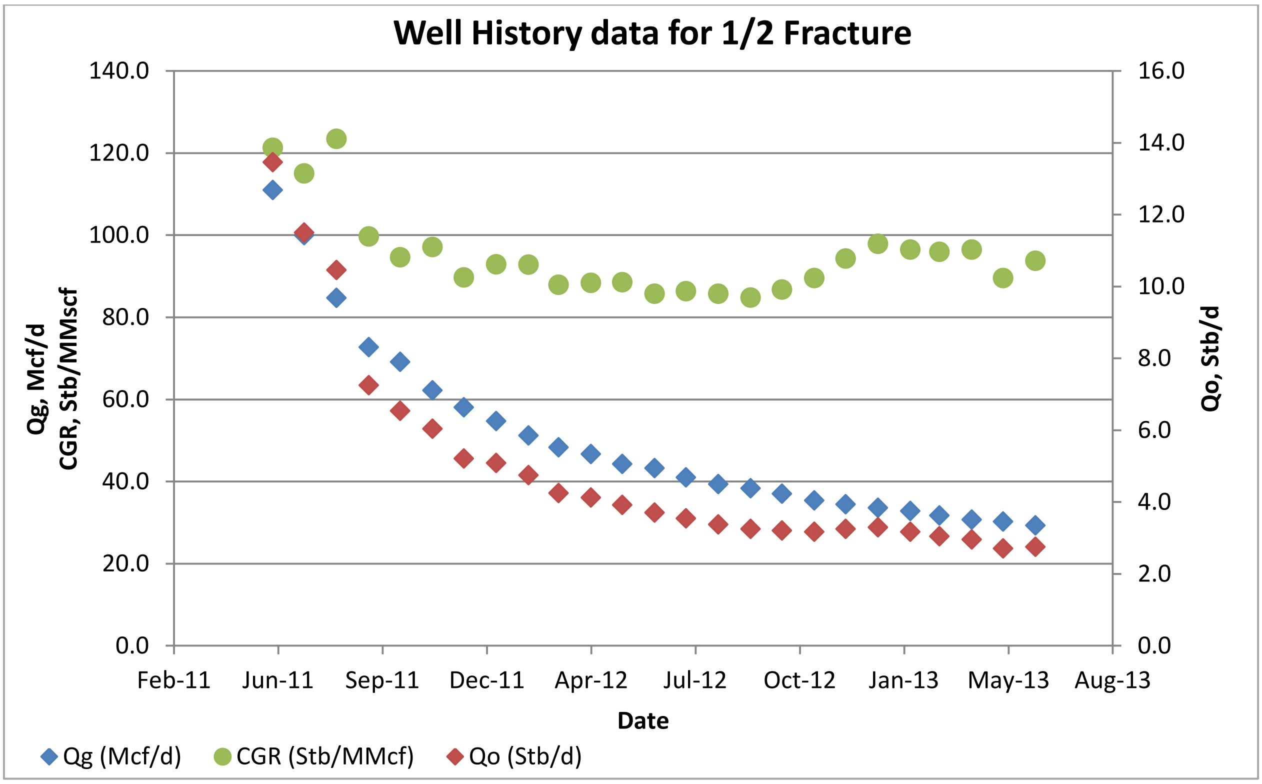

Figure A- 8 Analyzed historical data for half fracture segement assuming 12 stages courtesy of Trilogy Energy