Analytical and Numerical Investigation of Transient Behaviour in Hydraulically Fractured Tight Gas Reservoirs

A thesis submitted in fulfilment of the requirements for the degree of Doctor of Philosophy (PhD) in Petroleum Engineering of Imperial College London

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Declaration

Originality

I declare that this thesis is entirely my own research and is expressed in my own words.

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Publications


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Abstract

Development of tight gas reservoirs has long been affected by a lack of understanding of the complex flow profiles, and of the impact of very low permeability on reservoir productivity. Most well tests of tight dry gas wells are of short duration; well test interpretation often becomes difficult and non-unique when the duration of pressure buildup is too short. Thus, such tests typically lead to multiple interpretations and open-ended conclusions. The issue becomes even more complex as simulation software fails to adequately model flow in fracture networks.

Presented and investigated here are a series of well tests conducted in tight, naturally fractured, dry gas sandstone reservoirs for long durations: 100 hours in most cases, and 1,000 hours in two extended well tests. Well test responses from these tests were ambiguous. Surprisingly, the transient pressure analysis signature of these tight, naturally fractured, dry gas reservoirs is similar to the signature from lean gas condensate reservoirs. Lean gas condensate reservoirs usually exhibit a two- or three-mobility radial composite model response in the buildup analysis because of the existence of a condensate bank. However, this cannot be the explanation in the dry gas example. Possible causes for the similarity of well test analysis signatures of post-fractured, tight, dry gas and lean gas condensate reservoirs are discussed.

The primary objective is to document and characterize the observed behaviour of well tests in unconventional (tight) fields and, secondly, to determine how to analyse these test data, with the goal of obtaining the parameters of the induced fracture and the discrete fracture network (DFN).

Primary investigation has explored the possible direct causes (i.e., those related to wellbore, geology, or specific well conditions) that could result in the ambiguous well test response. However, because the well test response has been found repeatedly in a variety of regions around the world, it may not be related to any of those factors. This case study was approached as a direct problem by making a series of conceptual assumptions and investigating their impact on the well test response.

Within this context, the possible impact of scale-dependency of properties of fracture networks on the well test response is considered. It is argued that the anomalies in the well test response may reflect a step in the scale-dependent properties of the fracture network. Results suggest that the response reflects the scale-dependence of the intrinsic permeability of the fracture network and a geomechanical effect due to the induced hydraulic fractures. This scale-
dependent property has its reflection typically in a change in permeability with relation to distance and time of flow and thus should be considered whenever planning to induce a hydraulic fracture in a natural fracture network.
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Chapter 1
Introduction

1.1 Background

Tight sandstone reservoir exploitation is expected to constitute a major sector of the future exploration activity of the current decade. In 1990, it reflected 15% of the total U.S. gas production, and in 2006, this fraction reached 40%. These reservoirs are expected to contribute 50% of the North American continent gas supply by 2025. It has been noted that tight sandstone reservoirs have the potential to provide a major part of the global energy demand by 2030 (19th World Petroleum Congress, 2008). Tight sandstone reservoir production accounted for 22% of total U.S. natural gas production in 2008; about 30% of Canada’s current natural gas production came from tight reservoirs (International Energy Outlook report, 2011). Global gas production is expected to increase by 50% by 2035, with unconventional sources of tight sandstone and shale gas and oil reservoirs supplying two-thirds of the growth (IEA World Energy Outlook, 2013).

In addition to the fact that tight sandstone exploitation represents a major part of the future gas supply resource base, it is currently seen as a major source of knowledge that may be applicable for shale gas exploration due to its similarity in terms of low permeability as well as naturally fractured reservoir characteristics. Historically, if not since the discovery of hydrocarbons, the focus has been on development of high-permeability reservoirs that are oil- or gas-bearing. The easy access to natural gas resources found in abundance in highly permeable, thick, homogeneous, layer-cake sandstone reservoirs has overshadowed focus on the tight part of the gas resources. Most if not all technology and techniques used for oil has been applicable for gas as well, and the development of specific tight gas tools and techniques has not been a priority up to date. Because oil and gas were originally found in abundance in highly permeable formations, conventional exploration and development techniques were typically more economically viable when compared to the costly development of tight sandstone formations. At the beginning of 2000, due to the high oil prices, the industry went to the other extreme—into ultra-tight reservoirs, i.e., shale reservoirs, with permeability of 100 to 500 nano-Darcy. This has been successful in North America; however, it comes at the expense of massive fractures that in some cases have been reported to cause seismicity. In addition to
the huge water requirements, and partly for this reason, it has not spread much outside of North America (e.g., China).

Therefore, it is useful to now look at the in-between range, of 0.1 to 0.001 md, which is 100 times more permeable than shale but also 100 times, or more, less permeable than “normal” reservoirs. This in-between category may allow us to unlock the gas with a much smaller footprint than is required in shale reservoirs.

Tight sandstone reservoir layers have low porosity and permeability, thus extensive stimulation operations are always needed to sufficiently enhance flow to be economically viable. In recent decades, due to the significant rise of oil prices and the global demand for gas, considerable effort has been put into the development of major gas fields. Focus then shifted to the unconventional part of the petroleum spectrum, as per the resources pyramid (i.e., tight gas, shale gas, and coal bed methane) originally discussed by Masters (1979). The main ambiguity in the characterisation of tight sandstone reservoirs is the lack of proper well test data due to the typical practice of short shut-in periods (Gochnour and Slater 1977; Webster 1977; Weatherill 1978). Because the matrix is tightly compacted and of very low permeability, its response to pressure transmission is slow; thus a long duration of pressure buildup is required to be able to identify the reservoir characteristics and have a clearly defined radial flow region.

In the early 1990s, the Gas Research Institute (GRI) cored and logged a complete tight gas well. This provided a good foundation of data and knowledge for better understanding of a tight gas reservoir; however, the tests performed pre- and post-fracturing were conducted for short durations.

Several studies were made utilising the strength of the newly developed simulation software programs to predict productivity in tight sandstone reservoirs (Dreier et al. 2004; Carlson and Latham 1993); however, they are based on synthetic data and thus reflect numerical assumptions upon which the simulation process is based. Field experiments were conducted by Jeffrey et al. (2009) on tight formations via surface mining; however, due to the nature of the surface operation, no long-duration, in-situ tests were performed.

Recently, several new technology tools, such as the modular dynamic testers that were developed for conventional reservoirs, were tested on tight sandstone reservoirs. Unfortunately, they failed to provide the main parameters that are required for proper stimulation design (e.g., initial reservoir pressure and skin); the tightness of the sandstone formation layers only allows flow for extended production flow periods, which is not possible for these relatively small-volume tools. The only way to acquire the reservoir parameters needed for proper stimulation
design in unconventional tight sandstone reservoirs is to utilise the conventional method of well testing. Thus, it is concluded that the only way to effectively test tight sandstone reservoirs is by conducting well tests for long durations.

Unlike documented tests of short duration, the present analysis is based on actual well test data from a typical, tight, dry gas reservoir in a North Africa field tested for prolonged shut-in periods. An anomaly is identified in the post-fracturing well test derivative data. The anomaly has been noted in multiple tests in different reservoir structures of the same field. The same signature was also identified in well test data from wells in Canada and the Middle East.

The aim is to conclusively explain, backed by numerical modelling, why the well test anomaly is present in wells drilled in tight, naturally fractured, dry gas sandstone reservoirs, and what it represents. An additional goal is to investigate if the anomaly is related to the well, the induced fracture, the natural fracture network, or a combination of all three and, if so, to identify the percentage contribution from each factor. Well test data is analysed analytically and by numerical simulation to develop an explanation for the post-stimulation well test anomalies observed in tight sandstone reservoirs.

The analysis is structured into three stages: quantification, characterisation, and source identification. The hypothesis is that the signal anomaly is related to the fracture aperture distribution around the induced fracture in the wellbore region.

This report is organized in four main parts. Chapters 1 through 2 present the problem and the approach, followed by review of the literature of tight sandstone formations and the currently used modelling techniques. Chapters 3 and 4 present case studies of typical well test signatures and confirm their repeatability and analysis using typical analytical and numerical methods. Chapters 5 and 6 highlight the use of the discrete fracture network (DFN) concept to model tight sandstone formations by finite-element methods with the use of a two-way coupled geomechanical simulator via testing and analysis of different potential hypotheses proposed. Chapter 7 presents the conclusions, and proposal for future work.

1.2 Problem and Objective of the Research

Well testing is the process of flowing and then shutting in a well while bottomhole pressure is recorded. A transient pressure analysis is conducted to obtain the well test derivative. An anomalous signature is observed in well test derivative data from wells drilled in tight, naturally fractured, dry gas sandstone reservoirs following induced hydraulic fracturing (Fig. 1-1). Taking a closer look at the derivative curve, we note the details in Fig. 1-2.
Figure 1-1. Pressure transient and derivative plot of well test data from a tight shaly sandstone, dry gas reservoir post fracturing. Blue curve represents pressure; brown curve represents pressure derivative (adapted from Ecrin software).

Figure 1-2. Derivative plot of well test data from a tight shaly sandstone, dry gas reservoir post fracturing (adapted from Ecrin software).
The observed anomaly occurs in wells that share two main elements: the wells are tight, dry gas, sandstone reservoirs, and the well tests are performed post induced hydraulic fracturing. This anomaly is observed after the end of the bilinear (1/4 slope) or trilinear flow (1/3 slope), as referred to in some cases, due to that it represents flow from the induced hydraulic fracture, natural fractures, and flow from an elongated source (note; the wellbore storage effect was minimised due to downhole shut-in). The anomaly is characterised by a multiple radial composite behaviour and represents a change of storativity or diffusivity.

An alternate idealization for this anomaly could also be a laterally composite formation where both the hydraulic fracture encounters various zones of varying storativity or diffusivity in a linear variation rather than radially.

1.3 Approach

The well test response illustrated in Fig. 1-1 is similar to the response noted in well tests from lean gas condensate reservoirs. It is known that, in both dry and lean gas condensate examples, the anomalous response is caused by a change in permeability, as illustrated in Fig. 1-2. In the lean gas condensate examples, this change is caused by the condensate bank region that induces a change in the permeability of the system during the well test (Gringarten et al. 2000). However, this cannot be offered as an explanation in the dry gas example.
One possible explanation for the change in permeability of the zones around a well as one considers the larger and the larger zones was suggested by Jolly and Cosgrove (2003). They considered that the change in the properties of a fracture network resulted from the change in one parameter while all others remain constant. The results are illustrated in Fig. 1-3, which shows the connectivity of a fracture network made up of two orthogonal fracture sets. The number and spacing of the fractures in the three diagrams (a, b, c) remains the same; the only parameter that changes is the fracture length, which increases systematically from a to b to c. In each model, the connectivity between the upper and lower boundaries (separated by the distance L) is considered. In the network shown in Fig. 1-3a1, the fractures are 0.05L; in Fig. 1-3b1, they are 0.08L; and in Fig. 1-3c1, they are 0.11L. In the (a) models, there is no connectivity between the two boundaries, as shown in Fig. 1-3a2. In (b), the connectivity is channelized; in (c), it is effectively pervasive.

Jolly and Cosgrove noted that this change in property of the fracture network with change in length of the fractures can also be observed in the fracture network shown in Fig. 1-3c1. Over the distance L (i.e., the separation of the upper and lower surfaces), the connectivity is effectively pervasive. However, over smaller distances this is not so. Smaller areas of channelized connectivity can be identified, as can even smaller areas of no connectivity. Thus, if a well is drilled into such a network, the connectivity of the area immediately surrounding the well is likely to be low or non-existent, and the generation of hydraulic fractures would be needed to link the well into the channelized and more pervasive connectivity of the network.

It is suggested that this scale-dependent property of the network might account for the anomalous derivative curves observed in some tight reservoirs at longer scales. The aim of this study is to use numerical modelling to test this assumption, and confirm it with actual well data.

1.4 Conceptual Models

For the uncoupled flow simulations, two conceptual models of fractured reservoirs containing a single hydraulically-fractured well were initially developed, populated with properties such that the permeability increased with distance away from the wellbore in a manner consistent with the model suggested by Jolly and Cosgrove.

Note that these two conceptual models were not intended to represent real geological features, nor were they intended to explicitly represent a naturally fractured rock mass into which a well had, by coincidence, been placed. Rather, their purpose was to provide models within which the permeability variations might represent the multi-zone regions where the
natural fractures were actually distributed or parameterized as described by the models postulated previously for the observed composite behaviour in the well tests.

In the first conceptual model (Hypothesis A), it was assumed that the zone around the hydraulically induced fracture is compacted or stressed, causing permeability degradation, creating a zone of reduced mobility near to the hydraulic fracture (i.e., Zone 3 in Fig. 1-2). This was simulated by applying a constant density of fractures but with a variation of aperture. The model was tested by simulating a degraded permeability around the fracture. The well test for this system was then modelled numerically and the resulting derivative curve examined.

In the second model (Hypothesis B), the concentric variation in permeability around the wellbore was by maintaining a constant fracture aperture and applying a variation (progressive increase) in density of the fracture network (i.e., Zones 2, 3 and 4 in Fig. 1-2).

**Figure 1-4.** Fracture networks made of two orthogonal fracture sets. The orientation and density of the fracture sets are identical and they differ only in the length of the fractures, which increases from models a to c. In models a₂ to c₂, the separation distance between the upper and lower boundaries increases from model a₂ to c₂. In the shortest fracture scenario (a₂), there is no connection between the upper and lower boundary; only those fractures connected to the lower boundary are shown. The model shows that the style of connectivity varies from none (a₃), through channelized (b₃), to pervasive (c₃). (Modified from Jolly and Cosgrove 2003).
In the third model (Hypothesis C) used in the geomechanics-coupled flow simulations, the fracture density and fracture aperture were assumed to be constant, and in order to generate the variation in permeability predicted by the Jolly and Cosgrove model, different geomechanical permeability multipliers (to account for changing pressures and stresses over the duration of a well test) were applied to the zones shown in Fig. 1-2.

In all three models, a hydraulically fractured well was included to simulate the generation of an induced fracture in the formation. Well tests were then modelled using a reservoir simulator in the case of the first two models and a reservoir simulator coupled to a geomechanics simulator (in the case of the third conceptual model), and the resulting derivative curves were examined.

![Figure 1-5. Styles of connectivity showing dependency of fluid pressure and geomechanics on connectivity (Modified from Jolly and Cosgrove 2003).](image)

In addition to the model proposed by Jolly and Cosgrove, there are other possible explanations for the changes in permeability indicated by the derivative curves. These include the geology, phase segregation, and gauge resolution. Before the scale-dependent model is tested, it is necessary to demonstrate that these other possible causes are not responsible for the anomalous well test derivative curves. This is discussed in sections 3.12, 3.13 and 3.14.
1.5 Proposed Methodology and Thesis Outline

- Definition of Tight Gas Sands
- Literature Review
  - Dry Gas
  - Gas Condensate
  - Fractured Reservoir Response in WT
  - Geomechanics
- Methodology
  - Well Test
    - Data Mining
      - Data Filtering and Selection
      - Repetitive Signature
      - Primary Direct Investigations
    - Geology
      - Phase Segregation
      - Gauge Resolution
- Direct Problem Assumptions
- Numerical Simulation of Assumptions
  - Finite-Difference Method
  - Finite-Element Method
  - Two-Way Coupled Finite-Element Geomechanical Simulation
- Conclusions and Results

Figure 1-6. Thesis outline.
Chapter 2
Literature Review

2.1 Literature Review of Fluid Behaviour and Tight Sands
To form a foundation for this study, this section presents definitions of tight gas sands and a critique of published literature of lean gas condensate well tests, naturally fractured reservoirs, geomechanics of tight gas reservoirs, and finite-element, finite-volume simulation research.

2.1.2 Tight sand definition
The Gas Research Institute (GRI) defines three categories of tight reservoirs:

- Tight gas sands.
- Coal bed methane.
- Shale gas (gas in fractured shale).

Different definitions can be found for tight sands, the differences are dependent on the permeability range of various areas. Several technical definitions of tight gas sands have been made, starting with Archie (1950) and more recently by Holditch (2006) and Stottes et al. (2007). In this study, the most recent definition that was defined by Holditch (2009) will be used: “Tight gas sands are reservoirs that cannot be produced at economic flow rates nor recover economic volumes of natural gas unless the well is stimulated by a large hydraulic fracture treatment”.

2.1.3 Review of tight gas reservoirs
Gochnour and Slater (1977) compared two field cases, one from a tight carbonate formation in Canada and a second case from a West Texas gas well, with permeability range of 0.16 mD to 1.6 mD. They confirmed that the conventional analysis is difficult in tight formations and confirmed the necessity for simulation models in the interpretation of tight gas reservoir well tests.

Webster (1977) discussed completion practices in tight reservoirs, and highlighted ways to reduce drilling and completion cost. Weatherill (1978), in tight gas well test analysis of cases from the Alberta foothills, matched actual well test data with simulated data and acknowledged that wellbore storage dominates a large part of the well test and thus may confuse actual interpretation with wellbore-dominated effects. Holditch and Laufer (1978) described a process for determining optimal fracture length in a low-permeability gas reservoir.
Lee and Holditch (1981) discussed fracture evaluation with pressure transient testing in low-permeability gas reservoirs. Evaluations of different theoretical techniques were tested on data from 13 different wells, and they highlighted the limitations of several techniques.

Branagan and Cotner (1982) investigated the effect of mud filtrate invasion in tight gas reservoirs. They concluded that the pressure data will not reflect the actual reservoir parameters, and significant errors will be introduced into post-fracture well test analysis unless pre-fracture drawdown tests are sufficiently long. The entire well test can be conducted and the reservoir will not be significantly disturbed beyond the zone of increased saturation (i.e., the “probed” zone) in tight formations.

Kazemi (1982) reviewed the production of tight gas sands in the Rocky Mountain area of Utah and recommended the placement of a massive hydraulic fracture and the use of flow simulation to aid well test analysis interpretation of hydraulically fractured, tight sandstone gas reservoirs. Similarly, Holditch et al. (1983) illustrated by field examples that mud filtrate invasion into the near-wellbore region prior to a drillstem test (DST) significantly reduces the gas flow rate during the test. For short flow times and low permeability, this reduction in flow rate may be greater than an order of magnitude. Spencer (1985) noted that capillary pressures can create formation damage because of water blocks caused by imbibition of mud filtrate and hydraulic fracture liquids.

Lee (1987) acknowledged that many well tests of tight, gas sandstone reservoirs yield inconclusive findings because they are conducted for short durations. Unfortunately, even to date during the data mining stage of this thesis, it was observed that many well test results from tight gas formations are precluding any conclusive findings, owing to insufficient test duration. Payne and Cormack (1989) acknowledged that potential improvements in productivity of tight gas reservoirs can be achieved with better fracture conductivity and design.

Northrop and Frohne (1990) conducted field laboratory experiments in multiple wells aimed at improved characterisation and gas production from low-permeability reservoirs. They reviewed multidiscipline aspects of tight reservoir fields and provided in-depth studies of a sequence of low-permeability gas reservoirs.

GRI conducted intensive field experiments in 1991 on the Taylor sandstone formation in a well in Waskom field, Harrison County, Texas. These tests included core analysis and well testing post fracturing operations. The main objective of the Stage Field Experiment (SFE) program was to validate the effectiveness of the technologies developed by the GRI Tight Gas Program. GRI concluded that drilling horizontal wells and/or stimulating the formation by hydraulic fracturing is the only way to obtain commercially viable production from tight, gas
sandstone reservoirs. Emphasis was given to perform efficient pre-fracture well tests prior to stimulation treatments. As there can be a significant degree of ambiguity, the analysis of a post-fracture well test requires pre-fracture test results to provide the relevant reservoir parameters, such as initial reservoir pressure; this would reduce the ambiguity in the interpretation of post-fracture tests.

Carlson (1993) presented theory, assumptions, and algorithms associated with the implementation of a discrete fracture network (DFN) model as a new type of model for tight, fractured gas reservoirs. El-Banbi and Wattenbarger (1996), in the analysis of commingled tight gas reservoirs, identified that non-Darcy flow effects can be ignored, as they are not significant. However, they are significantly important in high-permeability reservoirs and therefore should be taken into account.

More recently, Arevalo-Villagran et al. (2003) noted that one of the most important causes of permeability anisotropy in tight gas reservoirs is the presence of natural fracturing in the formation. Garcia et al. (2006) reviewed the different types of tests that are applicable for tight gas formations and discussed why the traditional methods of tests and analysis rarely succeeded. Four cases of tight formations, ranging from 0.1 to 0.03 mD, which were tested for short duration, were compared with three synthetic cases of long and short duration. They concluded that when the pressure buildup duration is too short, forward modelling will be invalid, as several non-unique, good matches can be obtained.

From recent well test analysis results of tight gas sands, it has been concluded that transient buildup analysis is the only confirmed technique to accurately determine the reservoir pressure of tight gas sands. This technique does involve long pre- and post-fracture buildup periods to efficiently design stimulation techniques and identify the reservoir pressure.

### 2.1.4 Characteristics of regions around the wellbore—Gas condensate reservoirs

Evinger and Muskat (1942) proposed a pseudopressure method for solution-gas-drive oil wells. Fevang and Whitson (1995) extended the work of Evinger and developed a pseudopressure approach using a pressure saturation relationship calculated separately in each region. The pseudopressure integral corresponds to three flow regions (Fig. 2-1):

- Region 1 is an inner, near-wellbore region in which both gas and oil flow simultaneously.
- Region 2 is a region of condensate buildup in which only gas is flowing.
• Region 3 is a region containing single-phase (original) reservoir gas.

![Figure 2-1. Condensate saturation profile of a three-zone radial model (Gringarten et al. 2006).](image)

### 2.1.5 Well test analysis in gas-condensate reservoirs

Gringarten et al. (2000) investigated the difference in the two-zone radial composite model that is formed due to the formation of a condensate dropout region as the pressure around the wellbore drops below the dewpoint of the initial gas composition.

Bozorgzadeh and Gringarten (2004) introduced a new method of estimating the radius of a condensate bank. The method uses single-phase pseudopressure and is based on estimation of storativity ratios between the different zones as a function of the saturation profile during the well test. They investigated the existence of a three-phase region in and around the wellbore of gas condensate reservoirs and used it to efficiently characterise well test data and pressure/volume/temperature (PVT) fluid properties. The analysis uses a two- and three-zone radial composite model. The results proved that the composite behaviour is related to different phases within the wellbore and near-wellbore region and is not caused by faults or geological features.

Gringarten et al. (2006) further investigated the near-wellbore region and identified that the second, third, and fourth region appeared as three zones of different mobilities, exhibiting a three-region radial composite behaviour in a well test derivative (Fig. 2-2). The research included comparisons from different field areas (Fig. 2-3).
Figure 2-2. Schematic of buildup pressure and pressure derivative composite behavior (Gringarten et al. 2006).

Figure 2-3. Schematic of buildup pressure and pressure derivative composite behaviour in different areas of the world (Gringarten et al. 2006).
The typical results of the above derivative log-log plot of the pressure buildup response in the single-phase analysis showed a clear radial composite model, as expected, for the case model, with the well bottomhole pressure flowing below the dewpoint. The two-phase pseudopressure function that investigates the effect of relative permeability curves and fluid properties with distance was investigated by Raghavan (1995). However, the steady-state pseudopressure method ignores the presence of Region 2, in which the oil saturation is building up and where only gas is flowing. It assumes that both phases are mobile when the two phases are in equilibrium. The main reason for the difference is the choice of relative permeability. Raghavan demonstrated that the shape of the pressure buildup curve is a function of saturation distribution at the time of shut-in.

Zheng and Corbett (2005) introduced a workflow for evaluating the productivity of gas condensate reservoirs by numerical well testing to identify the radius of the condensate bank and production forecast.

Jamiolahmady et al. (2006) observed a correlation between relative permeability and capillary number. It was observed from the pressure derivative log-log plot that, even though the whole reservoir was below the dewpoint pressure, a radial composite model was observed as a consequence of mobility changes created by variations of oil saturations with pressure. These outcomes show the limitations of the two-phase pseudopressure method in the case of initial or average reservoir pressure below the dewpoint. In that case, it is concluded that a two-phase pseudopressure analysis cannot be applied if there is no indication of radial composite effect in the pressure derivative curve.

In tight reservoirs, as in our case, a total gas block effect may be observed because the gas is the only mobile phase in the near-wellbore region and tip/edge of the induced hydraulic fracture area when the well is shut in. This is attributed to the high pressure drops occurring in these two distinct regions. While the results have been proved to be applicable, we review the study from a different perspective—with more depth in the actual transient well test response behaviour in tight gas sands.

2.1.6 Review of dry gas reservoirs

In the case of dry gas wells, the entire test can be conducted away from the dewpoint, and no change in pressure will be observed that will initiate a condensate bank either in the near- or far-wellbore region (green path, Fig. 2-4).
Initially, while the test is being conducted prior to fracturing (pre-stimulation), the transient well test response will not indicate any boundary effect. As will be seen in several cases discussed in this study, the well test response prior to stimulation is usually dominated by a large wellbore storage period with no clear boundary response. This is typical in low-permeability reservoirs. Once a fracture has been initiated, two main pressure drops occur. These need to be differentiated between a reservoir response and a near-wellbore region response.

There are two main ways by which a significant pressure differential occurs, which may cause this behaviour:

- differential pressure occurs as a result of the extremely low-permeability non-fractured virgin reservoir region and the higher-permeability fractured region
- differential pressure occurs at the near-wellbore sandface region.

The latter has been thoroughly investigated in many literatures and documented for the different phases and quality of gases. However, the effect of the differential pressure caused by the extremely low-permeability, dry gas, non-fractured virgin reservoir region in the near-wellbore sandface area and its interaction with the natural fracture network is yet to be investigated.
2.1.6 Well test in dry gas reservoirs intercepted with finite and infinite fractures

Cinco-Ley et al. (1981) defined four main flow regimes through the fracture: fracture linear, bilinear, formation linear, and pseudoradial flow. These flow regimes define the flow in a well with an induced hydraulic fracture or in a well that intersects a large hydraulic fracture. These different flow regimes are characterised by four distinct flow profiles, each of which would exhibit a different well test derivative response.

Poe et al. (1999) performed a comprehensive fractured well production data analysis study based on analysing the production performance of more than 200 wells in low-permeability reservoirs in North America. They developed dimensionless time correlations for more accurately identifying the end of the bilinear flow regime and the start and end of the formation linear flow regime of finite-conductive, vertically fractured wells.

Initially, fracture linear flow occurs, which reflects the immediate flow of fluid and/or gas through the fracture conduit that would typically be of very high permeability and porosity due to the high-conductivity pathway. This would appear as a 1/2-slope trend line (blue line) on a log-log plot, as shown in Fig. 2-5.

Secondly, bilinear flow is usually exhibited in moderate to low $C_{fd}$ fractures (i.e., $C_{fd} \leq 50$). Bilinear flow is actually a combination of two flow paths, the first is the linear incompressible flow within the fracture, and the second is the linear compressible flow from the formation matrix to the fracture path. It is basically flow that is coming from the formation through the finite-conductive fracture, and the fracture tip effects are not yet visible. This would appear as a 1/4-slope trend line (green line) on a log-log plot, as observed in the upper curve in Fig. 2-5.

Thirdly, formation linear or pseudolinear flow is usually exhibited in moderate to low $C_{fd}$ fractures (i.e., $C_{fd} \leq 30$). It is a reflection of flow that is perpendicular to the fracture, and this flow dominates the flow path, with negligible effect from the fracture tip. This would appear as a 1/2-slope trend line (blue line) on a log-log plot, as shown in the upper curve on the plot in Fig. 2-5.

Finally, pseudoradial flow denotes that the flow has now stabilised and is coming from the entire system—from the matrix, through the fracture, to the wellbore. This would appear as a straight-line behaviour on a log-log plot (yellow line), from which the product of reservoir permeability $k$ and height $h$ ($kh$) can be obtained; it is shown in yellow on the plot in Fig. 2-5.

We introduce an additional flow regime, namely tri-linear flow that has been observed repeatedly in several cases that will be reviewed in later chapters. Tri-linear flow occurs as a transition between the bilinear flow and the linear flow regimes. It is typically characterized by
a 1/3-slope line (red line in upper curve, Fig. 2-5). Its occurrence is related to the very short bilinear flow regime, related to the high permeability of the fracture, and the formation linear flow.

In tight sandstone reservoirs with infinite-acting induced hydraulic fractures, we typically observe a low-permeability fracture flow characterised by a 1/4-slope trend line (purple line in Fig. 2-5, middle curve) followed by high-permeability fracture flow characterised by 1/2-slope trend line (brown line, Fig. 2-5). However, this is all dependent on the existence of wellbore storage and if the wellbore storage has masked the fracture flow or not (red line Fig. 2-5, bottom curve). The tri-linear flow regime will occur if there is intersection of the infinite-conductive fracture with the natural fracture network, and the length of time will depend on the permeability and density of natural fractures that may exist.

The presence of each fracture flow regime depends on the proppant concentration and distribution across the induced hydraulic fracture, as will be discussed in Chapter 6 Section 6.8.

Figure 2-5. Fracture response on log-log plot of transient pressure analysis data.

However, the trend lines do not reflect a required flow path, as the speed and character of flow of a certain stage may very well mask the effect of a preceding or previous flow profile. For example, the initial two stages—linear and bilinear flow—may both be masked by the effect
of wellbore storage, as the flow of the compressed fluid in the near reservoir area and the relatively small volume of the wellbore in addition to different compression ratios of the different fluid weights inside this area, expands. The tri-linear flow is more or less a reflection of a bilinear flow profile combined with the fluid flow from the reservoir matrix.

2.1.10 Summary
Lean gas condensate reservoirs exhibit a radial composite behaviour during the buildup test due to the formation of a condensate bank around the wellbore that is reflected in the transient pressure behaviour as a region of different mobility. Several researchers have identified and studied different ways of modelling these reservoirs and the reason for the composite behaviour has been noted.

Buildup tests of tight, dry gas reservoirs are typically conducted away from the dewpoint. If a radial composite behaviour is seen, it is a reflection of different permeability zones that could be attributed to different factors that are specific for tight, dry gas, sandstone reservoirs.

The natural fracture network, the effect of geomechanics, and the techniques for modelling these reservoirs and their behaviour are to be investigated to identify the reason for radial composite behaviours in well test data from tight sandstone formations post stimulation by induced hydraulic fracturing.

2.2 Literature Review of Analytical and Numerical Well Test Evaluation Techniques
The concept of well testing and analysis was introduced by Theis (1935). Working in the field of groundwater hydrology, he developed the Theis equation to describe transient drawdown during flow in water wells. Techniques for analysing well test data have evolved significantly over the last few decades. Recently, von Schroeter et al. (2001) developed a stable deconvolution algorithm to interpret geological properties from well test data. The complete history of well test development over the last century can be found in Gringarten (2008).

Well testing entails allowing the well to flow for a period of time (referred to as drawdown or flow period) after which the well is shut in for a period, which should typically be greater than 1.5 times the flow or drawdown period. The abrupt change in the well status (i.e., from flowing to shut-in) creates a pressure response, which is transmitted throughout the reservoir. In the context of this process, downhole pressure and rates are recorded with time, and a transient pressure response is created. The recorded pressure transient and rate are transformed to a pressure change, and a derivative plot on a log-log graph is created. This derivative plot,
together with the Horner or superposition plot, is used to calculate reservoir parameters, such as permeability, initial pressure, boundary conditions, and heterogeneities. Well test analysis remains unique despite all the new technology tools currently available because it is the only technique that provides near-wellbore and reservoir description up to thousands of meters into the reservoir.

2.2.1 Methodology of well test analysis
The methodology of well test analysis is based on an inverse problem approach. The flow period provides the input data of rate versus time; then the buildup period results in the output of pressure versus time (Fig. 2-6).

![Figure 2-6. Pressure response to a step rate change, first drawdown after stabilization (adapted from Gringarten 2008).](image-url)
2.2.2 Pressure analysis theory

In the move from Point 1 to Point 2 in Fig. 2-6, the difference in pressure represents the change of pressure $\Delta p$ from the initial reservoir pressure $p_i$ to the flowing bottomhole pressure $p_w$ in the well (Eq. 1).

$$\Delta p = p_i - p_w (\Delta t).$$

Since the initial pressure is equal to the bottomhole pressure before flowing the well, Eq. 1 can be expressed as Eq. 2.

$$p_i = p_w (\Delta t = 0).$$

This is then substituted into Eq. 1, thus yielding Eq. 3.

$$\Delta p = [p_w (\Delta t = 0) - p_w (\Delta t)].$$

This tracks the change of pressure during the drawdown or flow period (i.e., from the time the well was initially opened to flow). The change of pressure $\Delta p$ is then plotted versus elapsed time $\Delta t$ on a log-log plot. The log-log plot is compared to established type curves, which relate the shape of the pressure plot curve to a flow regime (e.g., homogeneous, double porosity, highly conductive fractures). This is known as the diagnostic plot (Gringarten et al. 1979), with the log of pressure change $\Delta p$ (psi) on the y-axis and log of elapsed time $\Delta t$ (hours) on the x-axis.

2.2.3 Pressure derivative

The pressure derivative plot is a plot of log $d\Delta p$ and $d\Delta p / d(\log \Delta t)$ on the y-axis versus log of elapsed time $\Delta t$ (hours) on the x-axis. This was first used by Djebbar et al. (1980) and was then identified as a powerful interpretation tool by Gringarten et al. (1979), Boudet and Gringarten (1980), and Bourdet et al. (1983). Its strongest application uses the derivative with respect to the natural log of $\Delta t$ to identify radial flow, the region where stabilised reservoir flow response is present.

The pressure derivative plot provides a viable method for reservoir description that is based on clearly identified flow regimes (Fig. 2-7). Wellbore storage can be clearly identified by a unit straight line, and the middle- and late-time regions of the log-log derivative plot provide information on reservoir characteristics.
Figure 2-7. Characteristic log-log pressure and pressure derivative plots for various hydrogeologic formation/boundary conditions (adapted from Spane and Wurstner 1993).

The log-log pressure derivative plot is typically divided into three regions. The early-time region relates to the wellbore storage in the case of surface shut-in. The middle-time region reflects the radial flow regime, and the late-time region identifies the limits of the reservoir boundary.

The stabilisation of the derivative is a function of mobility \((kh/\mu\), the permeability-thickness product divided by fluid viscosity\), and it is inversely proportional to mobility (i.e., the higher the stabilisation level the lower the mobility). Heterogeneous reservoir behaviour would typically be denoted by changes of the stabilisation level on one derivative curve. Storativity, on the other hand, is identified by the change between the initial and final stabilisation (denoted by \(\phi_{ch}\)).

The interpretation is based on the analysis of the pressure derivative with respect to the appropriate time function. The governing equations for the transient pressure behaviour used in well test analysis are satisfied by the diffusivity equation. However, the conditions that govern the diffusivity equation need to be valid, that is, the flow must follow Darcy’s law, where thermal effects are negligible and fluid compressibility is small; porosity, permeability, viscosity, and compressibility are constant; pressure gradients are small; and single-phase flow is present.
Reservoir behaviour including flow regimes that consecutively dominate the well test response during the test can be compared with type curves in order to identify the well model and estimate reservoir parameters.

![Flow regime identification tool](image)

**Figure 2-8.** Flow regime identification tool representing schematically the log-derivative of drawdown as a function of logarithmic time (redrawn from Ehlig-Economides et al. 1994).

Flow regimes are also identified with the straight-line method (Fig. 2-8), which still to date presents an efficient analytical method. These lines with specific angle inclinations are superimposed on the derivative plot to visually identify flow regimes.

In Chapter 3 Section 3.10.2, Fig. 3-28, we will see that there is a conclusion to be drawn by comparison of the buildup and the drawdown log-log derivative plots. Zheng et al. (2000) showed that different interpretation results can be obtained and result in misleading interpretation if the superposition is not considered for analysing the late-time response of the buildup and the drawdown. They proved that by comparison of results from two separate field cases using the superposition and de-superposition methods when applied to the buildup and drawdown analysis.

Zheng and Zhang (2014) investigated the use of temperature in well test analysis by using a non-isothermal wellbore model capable of predicting the temperature, pressure, flow rate and liquid fraction profiles under multirate and multiphase production scenarios. They proved that it may be used as a diagnostic tool to detect the end of the wellbore storage. In our subject case, the wellbore storage part is typically masked by the immediate response of the fracture that comes in with immediate transient behaviour at less than 0.1 hrs. However, as the temperature is above 100 °C, the existence of water is not possible.

### 2.2.4 Current techniques—Deconvolution

Deconvolution is a technique for converting the pressure and rate data obtained from a well operating under variable rate conditions into a much simpler form of the constant-rate
drawdown pressure response function. Basically, the pressure signals from both the drawdown and buildup are converted to a single-rate drawdown. This provides a relatively longer analysis period, which is not available from the conventional analysis, and thus provides the same pressure derivative normalised to a unit rate. The merit of deconvolution is that it provides a derivative that is free from distortions and errors from truncated rate history.

In 2001, von Schroeter et al. (2011) identified that the typical linear least squares methods used for deconvolution were inadequate to provide solutions with errors that are less than 1% in the rate signal and 5% in the pressure signal, and they developed a new method for deconvolution as a nonlinear total least squares problem. The new technique was able to provide smooth deconvolved response functions from data that was contaminated with up to 10% error.

The basic nonlinear total least squares deconvolution equation (von Schroeter et al. 2001) is

$$\text{Min}(y, z) \ E(y, z) = [p - G(z)y]^2 + v[y - q]^2 + \lambda[Dz - k]^2, ................(4)$$

where $p$ (pressure) and $q$ (rate) are inputs into the equation, and the initial pressure $y$ and $z$, which is a nonlinear coefficient of derivative interpolation, are estimated. $G$ is a matrix-valued function reflecting sampling and interpolation. Regularization is done via the matrix constant $D$ and vector $k$ such that $[Dz - k]^2$ is a measure of the total curvature of the response graph, and $v$ and $\lambda$ are weighted inputs that are either default values or user input.

### 2.2.4.1 Deconvolution process

The deconvolution process requires that the initial values input for $y$ (the initial pressure) and $z$ (nonlinear coefficient) are assumed values. This is best chosen on the basis of previous knowledge of the well or field; for example, pressure obtained from the modular formation dynamics tester (MDT) or reservoir formation tester (RFT) or from the initial drillstem test (DST) performed on the well after completion which will provide a guide to the initial reservoir pressure.

Using the initial defaulted values of $v$ and $\lambda$, an initial computation can be performed. Iterations from $\lambda = 10^2\lambda_{\text{def}}$ up to $\lambda = 10^2\lambda_{\text{def}}$, and then with the adopted $\lambda$ value are performed until pressure and rate data are honoured and an interpretable response is obtained. This is confirmed by ensuring that the initial pressure selected matches the entire pressure history, and
the difference in a detailed comparison of the deconvolved pressure matched with the actual pressure history is at least less than 5%. The same is applicable for the rate match.

Levitan et al. (2006) emphasized that deconvolution should only be applied to pressure and rate data that result from fluid flow that is governed by a linear set of equations. In gas reservoirs, the fluid-flow problem is nonlinear because the gas properties are strongly dependent on pressure. In some specific situations, this gas-flow problem can be linearised by the use of a pseudopressure transform, which allows deconvolution to be successfully applied to the data.

Amudo et al. (2006) summarised the deconvolution interpretation process as per the flow chart in Fig. 2-9.

![Figure 2-9. Deconvolution interpretation methodology (Amudo et al. 2006).](image)

Zheng and Fei (2008) tested the latest deconvolution algorithm by comparison of synthetic and field test data from different scenarios and compared the results with results using deconvolution with decline curve analysis. They confirmed its applicability and robustness with different data types for single-well analysis only.
Deconvolution is to be used for a linear system based on the rate-normalized pressure response to constant-rate production; however, as some systems are typically non-linear, Li et al. (2011) used the integration of numerical well testing and the deconvolution algorithm for analyzing permanent downhole gauge data to linearise the non-linear systems by dividing them into separate linear periods. They presented a workflow of three main steps. First step is to apply the total least squares method (TLS). Second step is to calculate the unit response and obtain the log-log derivative from the unit response. Third step is to obtain the first negative point of the log-log data and consider it as the boundary of the first linear system and then perform numerical well testing by forward modelling on each part separately.

Deconvolution provides information for a larger radius of investigation, and as boundary conditions become visible, the duration of an extended well test can be reduced or the optimal duration defined. In the case of dual porosity, the reservoir is typically heterogeneous and flow from matrix to fracture usually fluctuates, hence the use of deconvolution here is of vital importance. It would identify the region over which the interporosity flow is diminished and either radial flow or a boundary condition will be visible. In addition, dual-porosity response may be totally masked due to wellbore storage effects in the early-time region.

The complexity of our subject case is beyond the full capability of the 2D analytical models included in the typical well-test software programs. They fail to match the complete test data, including the early- and late-time regions. The typical models are made to provide a 2D solution by either matching a reservoir or a well model, but not both. In our study, we are investigating a case that includes an induced hydraulic fracture as well as a composite reservoir model. Typically, only a well model with wellbore storage and skin is available to be used with analytical radial composite reservoir models.

2.2.5 Radial composite model
The radial composite reservoir model describes a reservoir associated with wells that are in the centre of a homogeneous reservoir that is centred in the middle of another circular-shaped reservoir of different characteristics.

The initial well test response will typically reflect the inner zone, and the later response will represent the outer zone. A transition zone is then noted and, depending on the characteristics of the outer zone relative to the inner zone (i.e., better or worse), the well test derivative plot will have different shapes. Thus, the pressure derivative may have two stabilisation levels. The ratio of the duration of the two stabilisation periods is a function of the diameter of the zones and the mobility ratio.
Although the radial composite model may provide a positive description of several complex well test derivatives, it also can cause significant confusion for the interpretation because it is capable of providing a match to many derivatives. Thus, it cannot be a confirmed model unless previous geological knowledge of the field is available to confirm the results of the radial composite response. There are many other factors that may be well-specific that could also result in a radial composite well test derivative, such as drilling and completion fluid damage, well stimulation, or water flooding. The inner zone will reflect the inner damaged zone while the outer zone reflects the virgin reservoir response.

Lean gas condensate wells can typically exhibit a radial composite response due to the existence of a condensate bank in the near-wellbore region when the pressure falls below the dewpoint during the test. However, this is not applicable for dry gas wells.

Olarewaju and Lee (1987) presented an analytical radial composite model that included the effects of skin, wellbore storage, and phase redistribution. They noted that when the change in diffusivity between the inner and outer zone is not large, the pressure response can be confused with that of a dual-porosity response.

The effect caused by the reservoir drainage boundary may also be misinterpreted as composite reservoir behaviour.

2.2.6 Linear composite model
The linear composite reservoir model describes a well in a homogeneous reservoir that is not symmetrical on both sides, i.e., there is a difference in reservoir or fluid characteristics in the lateral extent away from the well on one side. This will reflect a difference in $kh$ and/or storativity. The well test response will typically reflect the inner zone closer to the well and then pass through a transition before reflecting the outer zone. Thus, two separate homogeneous zones can be identified on the derivative plot as two stabilisations. The first stabilisation will correspond to the mobility of the first zone and the second one will correspond to the average mobility of both zones.

Linear composite models are typically associated with wells that are close to a fault. Reservoir properties will typically be different on either side of the fault or well.

Martinez-Romero and Cinco-Ley (1983) presented a method to detect the distance from a well to a linear impermeable barrier by using transient pressure data. Ambastha et al. (1989) developed an analytical solution for pressure transient behaviour of a well in an infinite reservoir with skin at the linear discontinuity. They extended the study of Nutakki and Mattar
(1982) by providing a correlation for pseudoskin versus reservoir width for wells in various locations within a homogeneous reservoir strip.

Levitan and Crawford (2002) presented a new analytical solution for radial and linear composite models that is based on a special transformation variable that allows both continuous and discontinuous variation of rock and fluid properties.

### 2.2.7 Numerical well testing

Zheng (2006) reviewed several complex cases in which numerical well testing demonstrated that it is capable of identifying well test objectives that were beyond the scope of the typical analytical well test method, such as forward modelling for production forecasting, reservoir model calibration, reservoir modelling, and the detection of phase boundaries during production with the use of actual field cases.

Zheng and Li (2007) proposed the 4D well test analysis method for permanent downhole gauge (PDG) data analysis, utilizing numerical well testing with the neural network modelling technique, and demonstrated its applicability for reducing the uncertainty of production forecasting in gas condensate field cases.

Yao and Zheng (2009), introduced new advancement in numerical well testing with the use of streamline simulation techniques. Results of the streamline well test using the streamline simulation technique closely matched that of the conventional well test analysis techniques, but with the advantage of high-speed simulation and high stability due to its capability of solving equations in one dimension.

Zheng (2010), diagnosed the analysis of nonlinear transient pressure from PDGs, addressed a solution to compensate for the non-linearity of the data, and proposed to add a step to the well test analysis technique by applying the wavelet frequency analysis prior to the transient analysis. They demonstrated that the trend of skin change is eliminated by using this method.

### 2.2.8 Summary

Transient pressure analysis is the fundamental technique applied in well testing. In the analysis of the collected well test data, the pressure derivative plot is used to characterise well test responses that reflect the surrounding near- and far-wellbore region and is a useful tool to characterise the reservoir region far from the well. Several significant developments have been made to reduce the uncertainty in well test analysis, mainly with the use of deconvolution. However, the main analytical reservoir models that are currently used for reservoir description may be limited and inadequate to fully model a complex well with an ambiguous well test response.
2.3 Literature Review of Simulation and Numerical Modelling Techniques

Reservoir simulation is a powerful tool used to characterise the complex geology of reservoirs and mimic well behaviour in terms of productivity and fluid flow from the small pores of the reservoir to the wellbore. The application of modelling for many decades has driven major improvements on all aspects of reservoir simulators; they are now capable of modelling giant fields that include hundreds of wells.

Obviously all simulation results are a reflection of the input data, and the results will typically have the same uncertainty the input data had. However, significant improvements in tools and acquisition systems have reduced the uncertainties of all the input data. Detailed geological reservoir description derived from outcrops and advanced seismic acquisitions as well as major advances in openhole and cased hole data collection has significantly reduced the uncertainties of the data input into reservoir simulators. Results have become more reliable and confidence well-established with powerful production history matching tools and an enhanced ability to estimate future production.

The information technology revolution in the early years of the current decade has provided more powerful hardware and software that has further enhanced the use of reservoir simulators, making them more user friendly and adding speed and simplicity to previously complex and difficult simulation cases. However, the increase in computational power of simulators was also offset by higher-resolution 4D seismic that provided more detailed images of the surface. When that was coupled with detailed geological descriptions and outcrop data, more complex models became evident and required larger numbers of grid cells.

This study considers three categories of reservoir simulators: finite-difference simulators, finite-element simulators, and finite-volume simulators. This chapter presents a review of the latest advancements in the three simulation methods, the advantages and disadvantages of each, and their usual application, especially as it relates to this study.
2.3.1 Finite-difference modelling

Finite-difference modelling was the initial simulation method developed and it solved the differential equations with the use of the Taylor expansion:

\[ f(a) + f'(a)(x-a) + \frac{f''(a)}{2!}(x-a)^2 + \frac{f'''(a)}{3!}(x-a)^3 + \cdots \] ........................................(5)

This is simplified using summation notation as

\[ f(x) = \sum_{n=0}^{\infty} \frac{f^n(a)}{n!} (x-a)^n \] ................................................. (6)

Flow and simulation computations are based on the flow and mass conservation equation from one grid cell to the next, with material balance equations of flow from reservoirs to well production.

Sheldon et al. (1960), Stone et al. (1961), and Blair et al. (1969) presented the Implicit Pressure Explicit Saturation (IMPES) formulation for the black oil case, which is based on the following linearised expression:

\[ M_i I^{n+1} - M_i I^n = \Delta t \left( \sum_{j=1}^{N} q_{ij} I_j - q_{il} I_i \right) I, \] .................................................(7)

where

- \( M_{il} \) is mass of component \( I \) in gridblock \( i \)
- \( q_{ij} \) is the interblock flow rate of component \( I \) from neighbour block \( j \) to block \( i \)
- \( q_{il} \) is a well term.

Fagin and Stewart (1966) later provided an extension to the IMPES formulation to be applicable for any number of components and applicable for different models. Coats et al. (1980) later provided a compositional application to the IMPES model, the scalar multiplications requiring a small fraction of the work required for the implicit formulation. Thus, the model CPU time per grid block was much less for the IMPES formulation than for the implicit formulation. Coats et al. (2000) made the IMPES method applicable for two-phase (oil and water) systems by providing a solution of a water saturation equation using implicit saturations (mobilities).

The finite-difference method implements a square network of lines to discretise the partial differential equation (PDE) and forms grids that share the same PDE conditions. While its advantage is simplicity, simplicity is also its disadvantage due to its inability to deal with complex geometries. Finite-element modelling and finite-volume modelling were developed to overcome this disadvantage and enable the simulation of very complex shapes and surfaces.
In the petroleum industry, finite-difference modelling is applied mainly to simulate a massively large model that reflects a wide area with limited geological and depositional systems diversity (e.g., a homogeneous, high-permeability sandstone, a layer-cake reservoir). In this type of scenario, the numerical dispersion due to the upscaling of the grid blocks can be neglected due to the homogeneous characteristics of the reservoir. Faults and fractures are modelled by separate grid cells that would have different properties from the actual matrix grid blocks that are typically a line or cube-shaped. Single-well models and large-scale models with simple geological descriptions are modelled with the finite-difference modelling technique for the purpose of production and reserve estimation.

Finite-difference modelling has truncation errors against $\Delta x$ for the backward and the centred finite differences (Fig. 2-10). In Fig. 2-10, the slope of the lines is consistent with the order of the truncation error, i.e., 1:1 for the backward difference and 1:2 for the centred difference. The discrepancies between the actual data and the numerical results for the smallest values of $\Delta x$ are due to the use of finite precision computer arithmetic or round-off error (Peir´o and Sherwin 2005). Thus, typical numerical dispersion errors are applicable.

Figure 2-10. Truncation and rounding errors in the finite-difference approximation of derivatives (Peir´o and Sherwin 2005).
2.3.2 Finite-element modelling

The finite-element method is based on a set of functions, where $N_i(x)$ is known as the expansion basis. Its support is defined as the set of points, where $N_i(x) \neq 0$. Figure 2-11 explains the expansion basis which comprises piecewise continuous polynomials within each element.

$$u^\delta(x,t) = \sum_{i=1}^{N} u_i(t) N_i(x), \ldots \ldots \ldots \ldots \ldots \ldots \ldots \ldots \ldots (8)$$

where $u(x,t)$ is the rate of change.

Finite-element modelling is mainly used for the simulation of a complex reservoir with heterogeneous reservoir characteristics. Finite-element modelling is ideal for complex geological reservoirs because the sharp curvature and complex shapes in those reservoirs need geometric flexibility to be modelled.

Finite-element simulations are being applied more often because they reduce the smoothness requirements on $u$ and also make the matrix of the discretised system symmetric. The application of the boundary conditions leads to symmetric matrices, unlike in the finite-difference method.
Naturally fractured, tight sandstone gas reservoirs are reservoirs that typically have a high degree of complexity due to the uneven nature of the sort, type, intensity, and shape of fractures that can exist as well as their intersection and interaction mechanism with the heterogeneous matrix around them. Finite-element simulations are capable of modelling the complexity of naturally fractured, tight reservoirs.

2.3.3 Finite-volume simulation

Finite-volume modelling is similar to finite-element modelling but employs the use of hyperbolic equations, thus producing a conservative scheme.

More recently, a combined technique that combines finite-element and finite-volume modelling was devised by the use of unstructured hybrid finite-element, node-centred finite-volume discretisation developed as a hybrid finite-element–finite-volume discretisation (Paluszny et al. 2007).

2.3.4 Finite-element–finite-volume simulation

The subsurface systems of tight, naturally fractured reservoirs are usually composed of a very complex, intersecting network of fractures that is highly heterogeneous and geometrically complex. Finite-element and finite-volume simulation methods have been widely applied, as they provide better modelling of complex formations. The finite-element model is basically a series of nodes surrounded by small areas, all gathered next to each other to form a mesh of finite elements (Fig. 2-12a). The finite-volume model is basically the same mesh with the addition of additional small areas surrounding centre nodes inside each mesh shape, thus forming a finite volume (Fig. 2-12b).

![Figure 2-12. Schematic of a finite-element and finite-volume mesh (Geiger et al. 2009).](image)

Narasimhan and Witherspoon (1976) suggested the possibility of developing a new finite-element model (FEM) code that can incorporate the explicit and implicit iterative solution scheme using the Trump computer program (Edwards 1972), a technique by which explicit calculations are carried out for those elements where $\Delta t < \Delta tm$ and implicit calculations are carried out for the balance where $\Delta t > \Delta tm$, where $\Delta tm$ is the critical timestep. Thus it combined
the advantages that are inherent in both the integrated finite-difference model (IFDM) and the FEM. The key difference between a fully coupled, weighted FEM and IFDM is in the calculation of the fluid pressure gradient. Huyakorn and Pinder (1978) developed a new, improved solution of the two-phase immiscible flow equations based on finite elements.

In summary, finite-element modelling is a technique for obtaining approximate values of a parameter by computing the variable values of its neighbours, for example, the average of the neighbour’s values of a typical variable, such as fluid pressure, in the subsurface system. Similarly, finite-volume modelling is a technique based on equal flux inlet and outlet volume, thus it is based on mass conservation, such as in fluid flow. The finite-element–finite-volume (FEFV) method is based on the obtained approximate values of each parameter, derived from the parameter values of its neighbours as well as the mass conservation technique (i.e., it is a combination of both the finite-element and finite-volume methods). The FEFV method is particularly efficient in modelling complex geological geometries that contain thousands of fractures composed of a wide range of size and length, from millimetres to kilometres.

Karimi-Fard et al. (2003) developed a simplified, discrete fracture model that handles 2D and 3D systems that include fracture-fracture, fracture-matrix, and matrix-matrix connections. Recent research with FEFV modelling focused on different interests such as that of Monteagudo and Firoozabadi (2004), who extended the work of Karimi-Fard et al. (2003) and Geiger et al. (2003) and provided a numerical method for modelling two-phase immiscible and incompressible flow, taking into account both the capillary pressure and gravity effects for discrete-fractured media.

Fu et al. (2005) developed the 3D, three-phase, black oil simulator based on the FEFV method and confirmed its application on 3D two-phase simulations, 3D three-phase simulations, and 3D three-phase simulations in a complex domain. Reichenberger et al. (2006) presented a vertex-centred FV model for two-phase flow in fractured porous media in which fractures are discretely modelled as lower-dimensional elements.

Paluszny and Zimmerman (2010) introduced a numerical framework for 3D discrete crack growth with the use of arbitrary tetrahedral meshes. Fracture growth is modelled on the basis of three criteria: propagation magnitude, direction, and a failure criterion.
2.4 Literature Review of Induced Hydraulic Fracture Simulation

Fracture stimulation and simulation and testing of induced hydraulic fractured reservoirs is a complex problem that has promoted the development of sophisticated simulators and an expanded understanding of reservoir properties heterogeneity and fracture propagation and how the induction of hydraulic fractures produce a change on the pre-existing natural fracture network.

In 2006, Zhang et al. studied the effect of in-situ stress state on the geomechanical and hydraulic responses using 2D modelling of the Gullfaks reservoir in the North Sea. They observed that a small change of the effective stress caused by fluid-pressure changes in the reservoir is likely to trigger reservoir-wide reactions irrespective of whether the change was at a local scale or a reservoir scale.

Weng et al. (2011) investigated the modelling of hydraulic fracture networks in naturally fractured formations and developed a model to effectively explain complex fracture network propagation in naturally fractured formations. This was based on governing equations that take into account the stress shadow, fracture interaction, fracture height growth, and proppant transport. The study illustrated that the pre-existing minimum and maximum horizontal stress has a major impact on the hydraulic fracture network that is created during the fracture treatment. While some comparison can be made using the Unconventional Fracture Model (UFM) model when compared to microseismic data, it will still not be a perfect match because the model is based on the design criteria and not actual pumped fracture treatment. It was stressed that the comparison needs to be made, using a model that integrates the actual pumped treatment as well as the effect of the geomechanics.

Gu et al. (2011) developed a criterion, based on laboratory experiments, for evaluating the effect of the intersection angle of the crossing of the hydraulic fracture and the natural fracture.

Cipolla et al. (2011) investigated the effect of the propped and unpropped section of the natural fracture network and concluded that as the height of the propped section increases, the production rate also increases. The study was based on data from the Barnett shale gas field.

Mirzaei and Cipolla (2012) highlighted the importance of properly modelling hydraulic fractures in shale gas reservoirs with complex natural fracture networks and identified that an unstructured complex grid can overcome the local variation of the structure and rock properties’ variation in unconventional reservoirs.
Zhou et al. (2012) presented a semi-analytical method that combines the analytical solution with a numerical solution on discretised fracture panels. A production simulator based on a grid-less fracture network (mesh-based) was developed on the basis of analytical solutions of flow from the reservoir, fracture, and wellbore. The purpose is to evaluate stimulation effectiveness. It was noted that the flux comes from the near-wellbore fracture panels; however, most of the production is from the outer part of the fractures at stabilization.

McClure and Horne (2013) proposed the Tendency for Shear Stimulation test (TSS test) as a method for determining the effect of shear stimulation on formations. With the use of the DFN 2D simulator, numerical simulations were performed to couple fluid flow with stress induced by fracture deformation. By comparing two applications with the TSS test, it was determined that the results cannot be interpreted easily and the pressure transient tests are vitally needed to interpret the results of the TSS test. However, the TSS test is performed by injection of fluid at a pressure that is equivalent to the bottomhole pressure and below the minimum principal stress, which is unlike the actual stimulation, which creates the induced hydraulic fracture by injection of fluid and proppant at pressures that are above the formation pressures and applies stresses that are above the minimum principal stress.

Wallace et al. (2014) investigated the effect of heterogeneous rock properties, fluid interaction, thermal effects, phase entry, and natural fractures on the interpretation of diagnostic fracture injection tests (DFITs) in unconventional tight reservoirs by comparing actual shale gas data and model-simulated data. However, DFIT's typically have very short test durations; the test was proved to be reliable in providing fracture closure pressure estimates only and unreliable in estimating reservoir behaviour.

Urbancic and Baig (2014) demonstrated how advanced seismic signal analysis techniques, such as the seismic moment tensor inversion (SMTI) approach, can be used to evaluate pre-existing fracture networks in naturally fractured shale reservoirs that are stimulated and to identify their failure type, the fracture connectivity measured in terms of the number of intersecting fractures in a volume as well as the fracture intensity based on fracture length per volume, and the fluid pathway related to the flow in open detected fractures.

This current research project employs four different fracture models to investigate the response they predict on the well test transient pressure log-log plot. Khristianovic and Zheltov (1955) and Geertsma and de Klerk (1969) developed the Khristianovic–Geertsma–deKlerk (KGD) model, in which the fracture shape does not depend on the vertical position and the fracture has a constant and uniform height and a rectangular cross section. Perkins and Kern (1961) and Nordgren (1972) considered the plane strain assumption in vertical planes, so each
vertical cross section deforms independently of the others; this is known as the Perkins–Kern–Nordgren (PKN) model. Two additional models are addressed: the wire mesh model and the Pseudo 3D (P3D) model. Ben-Naceur (1989) defined the content of the fracture propagation model, which involves a blend of different components, such as rock mechanics, fluid mechanics, rheology, heat transfer, and reaction kinetics.

2.4.1 Naturally fractured reservoirs

Warren and Root (1963) developed the initial dual-porosity model that provided the basis for future dual- and triple-porosity models. They defined $\lambda$ as the parameter governing interporosity flow, and $\omega$, as the parameter relating fluid capacity of the secondary porosity to that of the combined system in dimensionless form.

The first triple-porosity model was developed by Liu (1981, 1983) via several laboratory tests and experiments conducted on naturally fractured rock specimens.

Jalali and Ershaghi (1987a) investigated the transition zone typically observed in naturally fractured reservoirs and proved that, in double-porosity and triple-porosity reservoirs, the transition response corresponds to both pseudosteady-state and nonsteady-state interporosity flow. Jalali and Ershaghi (1987b) identified a unified type-curve approach for pressure transient analysis of naturally fractured reservoirs. Belani and Jalali (1988) investigated the pressure transient response for uniform and bimodal distributions of block size and provided a method for the estimation of matrix block size distribution in naturally fractured reservoirs. Jalali et al. (1989) investigated why certain naturally fractured reservoirs do not experience sudden rate decline as predicted by classical double-porosity models, and developed an interporosity flow model for naturally fractured reservoirs. Johns and Jalali (1991) provided a comparison of the pressure transient response in intensely and sparsely fractured reservoirs by extending the previous dual-porosity models to incorporate fracture spacing variability. Moreover, they proved that in the absence of interporosity skin, intensely and sparsely fractured reservoirs show distinctions in the pressure response, and the uniformity of a fractured reservoir also significantly affects pressure response irrespective of the degree of fracture intensity.

Al-Bemani and Ershaghi (1991) modified the interporosity parameter to incorporate the contribution of relative permeability and capillary pressure effects associated with countercurrent flow and investigated two-phase flow interporosity effects on pressure transient test response in naturally fractured reservoirs. They stressed that, without proper consideration of two-phase flow and the saturation conditions, the estimated values for the interporosity coefficient, shape factor, and block sizes are subject to errors.
Al-Ghamdi and Ershaghi (1996) proposed new conceptual models to differentiate between micro fractures and macro fractures. El-Banbi (1998) presented a transient matrix-fracture-transfer linear reservoir dual-porosity model. Several models were reviewed to describe the production behaviour of tight gas wells and emphasize the importance of linear flow behaviour in tight gas wells. He then used a numerically inverted Laplace space solution to compile a catalogue of models for different flow boundaries and reservoir conditions.

Dreier (2004) addressed the limitation of the model developed by Al-Ghamdi et al. (1996), in that it assumed pseudosteady-state fluid transfer between fractures, and then he introduced two new quadruple-porosity models that account for fracture interconnectivity. Bello (2009) extended the applicability of the El Banbi linear dual-porosity solution to horizontal wells and confirmed its applicability on horizontal, multistage-fractured, shale gas wells.

Renshi et al. (2009) emphasized the use of the quadratic pressure gradient term in the transient well test analysis of fractured, vuggy carbonate reservoirs. Errors of up to 20% in the dimensionless pressure and 30% in the dimensionless pressure derivative may occur in specific cases such as thin-bed and heavy oil reservoirs.

Hasan et al. (2011) introduced a triple-porosity model by subdividing each medium and assigning different properties to porous media: matrix, less-permeable micro fractures, and more-permeable macro fractures. Definitions for six flow regions to identify fully transient triple-porosity models were made.

### 2.4.2 Geomechanics

Davies et al. (1998) investigated the relationship between net effective stress and in-situ permeability and noted that a significant decline in matrix permeability of tight gas sands can be seen as a result of an associated effective stress increase and depletion. They concluded that the rate of change of permeability with increasing values of stress is a function of the pore geometry.

Davies et al. (1999) investigated the decline in productivity during early production of idealized wells and illustrated that it is directly related to the impact of stress-sensitive matrix permeability. Their results concluded that, in unconsolidated reservoirs, a significant reduction of permeability occurs in the highest initial reservoir quality sands; sands with relatively low initial reservoir quality are less stress sensitive. Whereas in consolidated reservoirs, the loss of permeability occurs with increasing stress in sands with slot pores (tight-sand pore geometry consists of ultrafine micro porosity in an all-pervading matrix, long narrow tube-like). This stress sensitivity highlights the need to test tight gas samples at reservoir stress conditions in
order to obtain representative porosity-permeability relationships for correct reservoir modelling.

Holditch (2006) and Abass et al. (2009) noted that the small pore and pore throats in tight gas sands make these formations more stress sensitive compared to conventional, high-permeability sandstone reservoirs. The change in permeability associated with depletion has been explained through the unfavourable aspect ratio of the pores in these sandstones, which would usually be lenticular-shaped, with the smallest axis in the vertical direction. An increase in effective stress causes flattening and closure of these pores.

Walsh (1981) defined that a fracture is two rough surfaces in contact, and that flow can only be achieved when the viscous drag of the fluid between the two narrow surfaces overcomes the resistance to flow and the tortuosity of the flow path. He then derived an expression for fluid flow through fractures as a function of the external confining pressure and the pore fluid pressure and concluded that the effect of aperture and tortuosity are the two factors that control flow rate.

Ostensen (1983) extended the work of Walsh and introduced a theory of permeability based on flow through cracks. He presented an extensive comparison of data and theory that provided support to the Gaussian crack model and indicates that the permeability of tight sand cores is a result of micro cracks. The theory predicted that the square root of permeability should decrease linearly with the log of net confining stress. El Rabaa (1989) conducted an experimental study of hydraulic fracture geometry initiated in horizontal wells and identified that in vertical wells a single planar fracture may occur, whereas in horizontal wells non-planar fracture geometry patterns occur as multiple fractures away from the well, and their shapes and size will be dictated by the well inclination and azimuth relative to $\sigma_{\text{max}}$, the maximum compressive stress.

Field experiments were carried out on tight sandstone (surface mining) to measure hydraulic fracture growth in naturally fractured rock (Jeffrey et al. 2009). Tilt meters and micro seismic arrays were installed in the zone adjacent to where a hydraulic fracture was initiated. The layer in which the fracture was initiated was then revealed by mine-through mapping (i.e., mining a tunnel across the fractured zone). The purpose was to determine the fracture geometry; visual results indicated that the induced hydraulic fracture intersected with pre-existing natural fractures, shear zones, and veins that were adjacent to the hydraulic fractures. The hydraulic fracture trace was seen to propagate through solid rock and step along shear zones.
2.5 Summary

Whereas each of the three simulation tools has unique advantages and applications, the choice for this research was to use finite-difference simulation as a primary proof of concept to investigate the areas and regions close to the wellbore in tight sandstone reservoirs with induced hydraulic fractures. Secondly, the finite-element reservoir simulator was chosen as a means to effectively simulate the natural fracture network that is pre-existing in the reservoir. This will enable implementation of the dynamic fracture network (DFN) concept and synthesis of the properties of the fractures and the effect of the induced hydraulic fracture on the natural fracture network in an attempt to investigate and measure the effect the induced fracture may have on well test simulation results.

Modelling of tight, naturally fractured reservoirs is a relatively complex endeavour due to the existence of uncertainties, mainly due to the lack of knowledge of the distant extent of the DFN and of the matrix as well. The issue becomes even more complex when it comes to modelling the tight, naturally fractured reservoir post induced hydraulic fracture. The complexity is further increased because the system has essentially gone past the elastic state and crossed through to the plastic state of deformation.

In essence, there are at least three main factors that need to be taken into consideration, namely the mechanical deformation that is caused by the fluid pressure and the fracture propagation into virgin matrix as well as into the DFN, the flow, and proppant distribution within the fracture itself. Given that the entire process is actually induced in dynamic and in-situ conditions, attempting to model the process is not easy. The simulation typically will require the coupling of implicit fracture network modelling, the geomechanical in-situ stresses, and the rock properties as well as the dynamic induction of the hydraulic fracture. The irregular shape of the natural fractures and their complex intersection with the matrix material and each other creates a complex network that is best modelled with the use of the mesh approach. However, the wide range of fracture size and geometry still makes it difficult to physically model their existence in static conditions, let alone to predict their behaviour in dynamic conditions.

In this research study, we are modelling the process and evaluating the modelling results with well test data that is a measure of the in-situ state of the reservoir. And the well test process itself is a reflection of both a dynamic flow process that is followed by a static shut in process. Thus this is considered to be the best way to evaluate the modelling technique.
Chapter 3
Well Test Analytical Investigation of Field Case Studies

3.1 Study Field Overview
The well tests examined in this study are from wells in two structures, Garet el Guefoul (GF) and Bahar el Hammar (BH), that are located 150 km apart (Fig. 3-1), in a field in North Africa.

Figure 3-1. Map of study area showing locations of well tests (blue dots) in two structures, Garet el Guefoul (GF) and Bahar el Hammar (BH) (modified from Akkouche 2007).
The reservoir layers, depositional environment, and sedimentology of both structures are similar, composed of tightly cemented low-porosity sandstones (Fig. 3-2) that have (due to low permeability) sub-millidarcy range (1/10, 1/100, 5/1000th mD) permeability, and porosity of less than 5 percent; this is largely because the reservoir is composed of very old rocks (Ordovician) that are deeply buried. Thus it can be commercially produced only where fracture systems are present or when the reservoirs are fracture stimulated. Natural fractures are identified from FMI full-bore formation micro imager logs obtained from Well GF-6 (Fig. 3-3). Fig. 3-4 and Fig. 3-5 show examples of outcrop and surface visualization of naturally fractured, tight sandstones.

Figure 3-2. Stratigraphy of Ahnet field (Donzeau 1971; Hervouet and Duée 1996).
Figure 3-3. FMI fullbore microimager log in Well GF-6.

Figure 3-4. Outcrop of unit IV (Akkouche 2007).
3.1.1 Garet el Guefoul (GF) structure

The GF structure is a sub-meridian faulted anticline, and Well GF-2 (the subject well of this study) is positioned at the structural crest. The well penetrates into four Upper Ordovician reservoir zones (from youngest to oldest, here referred to as DMK, upper GEG, lower GEG, and GOS).

Gas rates measured in previous well tests are summarized in Table 3-1. The two reservoir intervals present in Well 5 have extremely low permeability, on the order of 0.005 mD from transient pressure analysis of DST-2 and DST-3. Well test analysis of Well 3 resulted in extremely tight formation response with very low permeability, in the range of < 0.005 mD. The Quartzites de Hamra (QH) formation has only traces of gas in Well 2. The underlying Cambrian section was not tested.

<table>
<thead>
<tr>
<th>Formation</th>
<th>Well Test Gas Rate (mscf/d)</th>
<th></th>
</tr>
</thead>
<tbody>
<tr>
<td></td>
<td>Well 1</td>
<td>Well 2</td>
</tr>
<tr>
<td>GEG</td>
<td>Marked as &quot;non-productive&quot;</td>
<td>9.531</td>
</tr>
<tr>
<td>GOS</td>
<td>Shale layer, not tested</td>
<td></td>
</tr>
<tr>
<td>AAT</td>
<td>Shale layer, not tested</td>
<td></td>
</tr>
<tr>
<td>QH</td>
<td>Shale layer, not tested</td>
<td>Gas traces</td>
</tr>
</tbody>
</table>
3.1.2 Bahar el Hammar (BH) structure
The BH structure is located 150 km south of the GF structure, both in the same field. It is composed of a sub-meridian anticline cut by two continuous normal faults and a few secondary discontinuous faults. Overall, the stratigraphy of BH is similar to that of GF.

In this study, the focus will be on the analysis of test data from Well GF-2; however, reference will be made to test results from Well BH-6 within the BH structure of the same field to defend findings related to Well GF-2.

3.2 Well GF-2 Overview and Reservoir Information
Well GF-2 passes through the Ordovician IV unit, comprising four distinct reservoir zones, here referred to as the DMK, upper GEG, lower GEG, and GOS. Each reservoir interval is referenced to measured depth from the rotary table (MDRT):

- DMK: 5695.8–5787.7 ft (MDRT) previously fractured during initial well completion
- GEG, upper: 5955–5987.8 ft (MDRT)
- GEG, lower: 6135.5–6168.3 ft (MDRT)
- GOS: 6972–7008 ft (MDRT).

The basic formation properties of GEG and GOS are listed in Table 3-2.

<table>
<thead>
<tr>
<th>Well type</th>
<th>Gas producer</th>
</tr>
</thead>
<tbody>
<tr>
<td>Formation name</td>
<td>GEG and GOS</td>
</tr>
<tr>
<td>Drains</td>
<td>Ordovician unit IV</td>
</tr>
<tr>
<td>Well deviation</td>
<td>Vertical</td>
</tr>
<tr>
<td>Minimum in situ stress</td>
<td>4,500–5,500 psi</td>
</tr>
<tr>
<td>Fracture gradient</td>
<td>0.77 psi/ft</td>
</tr>
<tr>
<td>Young’s modulus</td>
<td>6–10 Mpsi</td>
</tr>
<tr>
<td>Poisson’s ratio</td>
<td>0.21–0.33</td>
</tr>
<tr>
<td>Average porosity</td>
<td>6–10%</td>
</tr>
<tr>
<td>Permeability</td>
<td>0.01–0.5 mD</td>
</tr>
<tr>
<td>Reservoir pressure</td>
<td>~3,000 psi</td>
</tr>
<tr>
<td>Bottomhole temperature</td>
<td>118 °C</td>
</tr>
</tbody>
</table>
3.2.1 Well petrophysics
Basic petrophysical analysis of the four reservoir layers tested was performed to investigate the connectivity between the layers. The top layer (DMK) has high shale content, as indicated by the gamma ray response. The middle two layers are tight sandstones, which may not be connected due to a significant spike seen in the gamma ray response interpreted as a shale layer (Fig. 3-6). Separation of the two layers was confirmed by core analysis, which indicated a significantly tighter zone existed between these two layers (Table A-3 in Appendices). The bottom layer is also tight sandstone lithology. There are thick shale layers (80 m) above and below all four reservoir layers, the detailed petrophysical analysis is available in Fig. A-1.

![Figure 3-6. Petrophysical analysis of zones of interest in Well GF-2.](image)

3.3 Well GF-2 Stimulation and Well Test Overview
In Well 2, all four reservoir intervals within the Ordovician unit IV were stimulated:

- Stage 1: Acid stimulation of lower GOS formation (6972–7008 ft).
- Stage 2: Propped hydraulic fracturing stimulation (lower GEG at 6135.5–6168.3 ft)
- Stage 3: Propped hydraulic fracturing stimulation (upper GEG at 5955–5987.8 ft)
- Stage 4: Propped hydraulic fracturing stimulation (DMK at 5695.8–5787.7 ft).
Six well tests were performed. All reservoir zones were open during the first two tests; single-layer tests of all four zones were subsequently performed.

### 3.3.1 Well GF-2 fluid and gas properties

The samples analysed from Well GF-2 were found to be dry gas. Gas properties for the reservoir simulation model were correlated using empirical correlations (Figs. 3-7 and 3-8). Gas viscosity and formation volume factor versus pressure dependencies were calculated to be \( \mu_g = 0.01 \text{ c_p} \), and \( \beta_g = 1.07 \text{ rb/Mscf} \) for given specific gravity (molecular weight) and reservoir properties. The field gas production composition of \( \text{C1 + CO2 + N2} \) in this field is nearly 99\%, hence dry gas (See Appendix A.4, Tables A-5 and A-6, gas composition analysis).

![Figure 3-7. Dry gas PVT composition in Well GF-2.](image)
3.3.2 Data quality check

The sequence of well tests for each layer in the single well GF-2 is illustrated in Fig. 3-9. Quality check was based on the selection of a test that will have good analysable data in both the drawdown and the buildup phases. From all tests performed, Test 6 yielded good quality data in the drawdown and buildup periods; the other tests are also discussed, as they do exhibit the same repetitive anomaly in the buildup data.

![Phase diagram of gas properties in Well GF-2.](image)

**Figure 3-8. Phase diagram of gas properties in Well GF-2.**

- Zone d: DMK formation 5695.8–5787.7 ft
- Zone c: upper GEG formation 5955–5987.8 ft
- Zone b: lower GEG formation 6135.5–6168.3 ft
- Zone a: GOS formation 6972–7008 ft

![Well layer schematic and configuration of tests in Well GF-2.](image)

**Figure 3-9. Well layer schematic and configuration of tests in Well GF-2.**
3.4 Well test analysis

Well test interpretation is the interpretation of pressure transient analysis. Pressure transient analysis results are usually displayed on a log-log plot and these plots are typically compared with different type curves (models) published in the literature (Agarwal et al. 1970; Wattenbarger and Ramey 1970; McKinley 1971; Gringarten et al. 1974; Earlougher and Kersch 1974; Gringarten et al. 1979; Bourdet and Gringarten 1980; Bourdet et al. 1983).

The derivative shape shows different shapes and responses, particularly in the late-time region, that improves the interpretation process. This is primarily a model identification process to define the flow regimes on the different parts of the log-log pressure and derivative plot, i.e.; early-, middle- and late-time regions. From the early-time region, parameters such as wellbore storage, skin, fractures, and partial penetration values are derived from empirical equations. From the middle-time region, parameters are identified that are related to the actual reservoir matrix, such as homogeneous and heterogeneous: 2-porosity, 2-permeability characteristics. From the late-time region, parameters such as the infinite extent, specified rates, specified pressure and leaky boundary are identified.

Some interpretation may require the comparison between the middle- and late-time region results, such as composite reservoir response, that will reflect different permeability zones between the middle-time and late-time region.

The flow chart in Fig. 3-10 summarises the workflow for typical well test interpretation.
The model confirmation requires matching of the log-log derivative plot, Horner plot, and actual pressure history with the proposed model. However, even with that process done, it may not suffice the full validity of the well test interpretation, as several complex reservoirs and heterogeneous behaviour may very well fit in multiple models and lead to infinite results and open-ended conclusions. Thus the use and input of reservoir and background information, such as petrophysics, geology, seismic, and field knowledge, are required to reduce the uncertainty of typical well test interpretation.

Unfortunately, even with the typical process of well test interpretation followed and implemented either manually or with the use of several advanced softwares currently available in the industry, the process is not easy, and several verifications need to be done to provide a sufficiently acceptable reservoir characterization and description. Thus deconvolution is typically required to confirm the model obtained from the typical well test interpretation procedure.

Recently, even with the deconvolution process completed, further validation may be required, such as with numerical well testing.
3.5 Well Test Analysis Approach Using Deconvolution

Deconvolution is a technique used to convert the pressure and rate data obtained from a well operating under variable-rate conditions into a much simpler form of the constant-rate drawdown pressure response function. However, deconvolution should only be applied to pressure and rate data that result from fluid flow in the reservoir that is governed by a linear set of equations. In gas reservoirs, the fluid flow problem is non-linear because the gas properties are strongly dependent on pressure. In some specific situations, this gas-flow problem can be linearised by the use of a pseudopressure transform, which allows deconvolution to be successfully applied to that data. (refer to Eq. 4, p. 41).

The actual deconvolution process follows seven steps:

1. Because this study case consists of dry gas only, pressures are first converted to normalised pseudopressure in order to approximate a linear system; then divide pressure by the average production rate.
2. Apply deconvolution with various regularisation values to the raw data (pressure and rate).
3. Once a satisfactory derivative has been obtained, calculate a convolved pressure history with that derivative.
4. Compare the adapted rates and the initial pressure obtained from deconvolution with the measured values.
5. If the match is acceptable, use the deconvolved derivative to generate a unit-rate pseudopressure drawdown for a duration equal to that of the test.
6. Analyse this unit-rate drawdown in the conventional way.
7. The resulting model is then applied to the measured pressure data using the adapted rates, and the model parameters are refined until an acceptable match is obtained.

Because, as previously mentioned in Chapter 2 Section 2.2.4.1, deconvolution should only be applied to pressure and rate data that result from fluid flow that is governed by a linear set of equations, it is necessary to confirm that deconvolution is valid for our case. A review of the comparison between real gas pseudopressure m(p) versus actual pressure shows that the investigated cases are at high pressure; thus there is no deviation from a linear case solution. Fig. 3-11 shows the pseudopressure plot, with the I(p) = 1/mCt, the derivative of the pseudotime with respect to pressure for Test 5. It is noted that the intersection point of the black curve and the reservoir pressure of the investigated case falls within the region of the dotted
blue line which represents a linear relationship. Thus deconvolution can be applicable for the subject investigated cases.

![Graph](image)

**Pseudo Pressure m[p] vs Pressure [psia]**

**Figure 3-11.** Comparison of real gas pseudopressure versus actual pressure to confirm that our subject case falls within the range of linear behaviour (intersection of black curve, dotted blue straight line, and green dot).

In the following sections, the pressure history plot and the log-log derivative signature of each well test are presented. The deconvolution result of each test is compared with the actual pressure buildup derivative plot. Pressure verification is performed where adequate data are available (e.g., MDT data) and compared with pressure match of the entire test. All the well test pressure data and rates are uploaded to the same well test file as in Fig. 3-12.

Test 1 and 2 were conducted with all the layers open and the rates obtained from the production logging tool (PLT) were uploaded accordingly. Tests 3, 4, 5, and 6 reflect individual layer tests; associated with each test is the PLT production rate of each layer, respectively, as in Fig. 3-10. The analysis process is as follows;

1- Determine the initial pressure \( p_i \) from at least two buildup periods
2- Confirm the \( p_i \) with other \( p_i \) data (i.e., MDT or RFT)
3- Deconvolve the entire pressure history with the obtained \( p_i \)
4- Verify that the pressure history is matched.
3.6 Well Test Results (Analytical)—Tests 1 and 2

In this section, well test data from the four reservoir layers in Well GF-2 are presented together with the results of deconvolution applied to the entire well test period in stages. Deconvolution results are compared with the actual well test data, and the analytical model matches are included.

![Pressure History](image)

**Figure 3-12.** Time sequence and flow rates of all well tests conducted with the production logging tool (PLT) in Well GF-2.

Tests 1 and 2 were performed with all four reservoir zones open. Tests 3, 4, 5, and 6 were performed on each individual layer separately (GOS, lower GEG, upper GEG, DMK, respectively; Fig. 3-9). The complete testing time sequence, pressure history, and flow rates are reported in Fig. 3-12.

In this study, it is considered that the analysis of well tests 1 and 2 provide example of a multilayer test of a tight gas formation. Tests 3, 4, and 5 are examples of a single-layer test of a tight gas formation, and Test 6 is an example of a tight shaly sandstone gas reservoir after stimulation. An initial test prior to stimulation was performed on the DMK layer (Zone d in
Fig. 3-9); this will be considered as a virgin tight gas reservoir test. Table 3-3 summarises all well test data for each single layer.

Table 3-3. Summary of Well Test Sequence per Layer

<table>
<thead>
<tr>
<th>Test</th>
<th>Layer Tested</th>
<th>Test Type</th>
<th>Drawdown (hr)</th>
<th>Buildup (hr)</th>
<th>Comment</th>
<th>Response</th>
</tr>
</thead>
<tbody>
<tr>
<td>Initial</td>
<td>DMK</td>
<td>Test data digitised</td>
<td>20</td>
<td>181</td>
<td>Single-layer test pre-stimulation</td>
<td>Composite</td>
</tr>
<tr>
<td>Test 1</td>
<td>All</td>
<td>DST</td>
<td>24</td>
<td>15</td>
<td>Perforation added at 2125.4–2136.03 m</td>
<td>Tight formation WT response, high skin</td>
</tr>
<tr>
<td>Test 2</td>
<td>All</td>
<td>DST and PLT</td>
<td>42</td>
<td>BU1: 124</td>
<td>PLT confirms only one phase—dry gas</td>
<td>Tight formation WT response, high skin</td>
</tr>
<tr>
<td></td>
<td></td>
<td></td>
<td></td>
<td>BU2: 24</td>
<td></td>
<td></td>
</tr>
<tr>
<td>Test 3</td>
<td>GOS; 6972–7008 ft</td>
<td>Slick line</td>
<td>48</td>
<td>100</td>
<td>Single-layer acid stimulation</td>
<td>Tight formation</td>
</tr>
<tr>
<td>Test 4</td>
<td>GEG; 6135.5–6168.3 ft</td>
<td>Slick line</td>
<td>48</td>
<td>119</td>
<td>Single-layer hydraulic fracture stimulation</td>
<td>Signature of a three-zone composite model</td>
</tr>
<tr>
<td>Test 5</td>
<td>GEG; 5955–5987.8 ft</td>
<td>Slick line</td>
<td>74.5</td>
<td>120</td>
<td>Single-layer hydraulic fracture stimulation</td>
<td>Signature of a three-zone composite model</td>
</tr>
<tr>
<td>Test 6</td>
<td>DMK; 5695.8–5787.7 ft</td>
<td>Slick line</td>
<td>259</td>
<td>488</td>
<td>Single-layer hydraulic fracture stimulation</td>
<td>Signature of a three-zone composite model</td>
</tr>
</tbody>
</table>

Data from tests 1 and 2 (all zones open) are combined and analysed as per flow rates derived from the PLT (Fig. 3-13). WT = well test.
Figure 3-13. Tests 1 and 2 in the same time sequence with PLT flow rates.

The log-log plots of the buildup period show high skin values pre stimulation (Fig. 3-14 and Fig. 3-15).

Figure 3-14. Log-log plot of Test 1 Buildup 10.
3.6.1 Deconvolution—Tests 1 and 2
Deconvolution was applied to different buildup periods from the combined tests 1 and 2, namely builds 10, 25, and 28. Comparison of the deconvolved derivatives of builds 10 and 25 and of builds 25 and 28 yields similar shapes and they converge at the late-time region, which may indicate closed-system behaviour (Fig. 3-16). A match of the entire pressure history is obtained for the same pressure (See Appendices, Fig. A-2).

Figure 3-15. Log-log plot of Test 2 Buildup 25 and 28.

Figure 3-16. Comparison of deconvolution of data from different builds of tests 1 and 2 and the derivative of each build up.
3.7 Test 3 Overview
Test 3 (GOS reservoir) pressure history plot (Fig. 3-17) contains one buildup period, flow period 34. Acid stimulation treatment had exceeded the reservoir pressure, thus a high-permeability fracture is expected to have been induced, as can be seen in the log-log plot (Fig. 3-18).

Figure 3-17. Pressure history of Test 3.

Figure 3-18. Log-log plot of Test 3.
3.7.1 Test 3 deconvolution
Deconvolution of the drawdown and the buildup (flow period 33 and 34) of Test 3 yields a unit slope straight line at late time, which may indicate closed-system behaviour (orange curve in Fig. 3-19). While the current dataset does not contain MDT or repeat formation tester (RFT) data for the subject layer, the verification of pressure is achieved by correlation with MDT pressure data from a different well in the same structure as a guide (Appendices Section A.6).

![Figure 3-19. Test 3 deconvolution plot. Blue curve is actual data derivative; brown curve is deconvolution derivative.](image)

3.8 Test 4 Overview
Test 4 (lower GEG) pressure history plot (Fig. 3-20) contains one buildup period. The log-log plots of the buildup data in Fig. 3-21 show the anomaly in the signature that is similar to the response of composite reservoirs, and a high-permeability fracture is noted.
3.8.1 Test 4 deconvolution
Deconvolution of Test 4 drawdown and buildup (i.e., flow period 40 and 41) compared with the complete flow periods of tests 1 and 2, including rate contribution obtained from the PLT,
yields a unit slope straight-line response at the late-time region (red curve in Fig. 3-22), which is similar to the response obtained for a closed system.

![Figure 3-22. Test 4 deconvolution. Blue curve is actual data derivative; red curve is deconvolution derivative.](image)

### 3.9 Test 5 Overview

Test 5 (upper GEG) pressure history plot (Fig. 3-23) contains one buildup period. In the log-log plot of the buildup in Fig. 3-24, a high-permeability fracture is noted, and the derivative shows a signature (anomaly) that is similar to the response obtained from composite reservoirs.
Figure 3-23. Pressure history of Test 5.

Figure 3-24. Log-log plot of Test 5 data.
3.9.1 Test 5 deconvolution
Deconvolution of Test 5 drawdown and buildup (i.e., flow period 38 and 39) compared with the complete flow periods of tests 1 and 2, including rate contribution obtained from the PLT, yields a unit slope straight-line response at late time, which is similar to the response obtained for a closed system (Fig. 3-25). A close match is obtained; verification of the pressure is achieved with the falloff test data as a guide (Appendix A, Fig. A-3).

Figure 3-25. Test 5 deconvolution. Blue curve is actual data derivative; brown curve is deconvolution derivative.
3.10 Test 6 Overview

Test 6 (DMK post stimulation) pressure history plot in Fig. 3-26 contains one drawdown and one buildup period. The log-log plot of the buildup in Fig. 3-27 shows the anomaly in the signature that is similar to the response obtained from composite reservoirs, and a high permeability fracture is noted.

![Pressure History](image1)

**Figure 3-26. Pressure history of Test 6.**

![Log-log plot](image2)

**Figure 3-27. Log-log plot of Test 6 data.**
3.10.1 Test 6 deconvolution
Deconvolution of Test 6 drawdown and buildup compared with the complete flow periods of tests 1 and 2, including rate contribution obtained from PLT, yields a unit slope straight-line response at late time, which is similar to the response obtained for a closed system (Fig. 3-28). Whereas no data are available in the dataset for the pressure verification, a match is obtained (see Appendix A Section A.5, Fig. A-3).

Here it is noted that the deconvolution result is also similar to the derivative obtained from the pre- and post-stimulation data of the same layer (red derivative curve in Fig. 3-28 obtained from digitized data), which may indicate a closed-system response. In essence, it is argued that the anomaly observed in the well test response is actually a result or the outcome of the induced hydraulic fracture, after which the system returns back to its typically tight and low-permeability flow characteristics.

Figure 3-28. Test 6 derivative and deconvolution curves compared with pre-fracturing test data. The red curve represents the buildup derivative of the data prior to fracture stimulation (data digitalized from hard copy of downhole test gauge).

3.10.2 Test 6 main buildup analysis
In well test 6, fracture response is noted in the log-log plot of data from the buildup and flow periods, after which a three-zone composite response is apparent in the log-log plot of the buildup period. Comparison of the drawdown and buildup indicates good quality data is apparent in both periods (Fig. 3-29), thus Test 6 will be used as the reference for the numerical simulation.
Here is noted that the response curves of the drawdown and buildup periods are similar and the response is similar to the response obtained from composite reservoirs. Previous deconvolution had shown that the system will progress toward a unit slope straight-line response at late time, i.e., the system returns back to its typical response in low-permeability reservoirs.

![Log-Log Rate Validation - Flow Period 5](image)

**Figure 3-29.** Comparison of Test 6 drawdown and buildup data in the DMK formation after stimulation of the zone at 5695.8–5787.7 ft in Well GF-2.

A rollover of the data trend line occurs in the late-time region in the buildup, drawdown (Fig. 3-29), and deconvolution data (Fig. 3-28). A decline in the buildup curve would typically be reflected as a rise in the drawdown curve at late time in the case of a geological boundary or a closed-system response. The well test response portrayed is an indication that, despite the long duration of the test (1000 hr), the reservoir boundary has not been reached. This indicates the tightness of the formation layer; on the log-log plot, the fracture is diagnosed after 5 hr, whereas the reservoir boundary was not reached even after 1,000 hr of shut-in.

The rollover in the trend lines in all the transient pressure analyses of the Test 6 data is similar to the trend seen in tests 4 and 5 and indicates that there is a major difference in permeability beyond the fracture region. While the analysis of the drawdown data is typically
hindered by noise, here it is just used to confirm the similarity in the drawdown and buildup response.

### 3.11 Comments on Pressure Derivative of Two-Zone and Three-Zone Radial Composite Models

The well test results obtained from the tight, dry gas sand reservoir after fracturing (tests 4, 5, and 6 in Well GF-2) are typical of a two- or three-zone composite response, with identical responses in the buildup and drawdown (Fig. 3-30), and a closed-system response in the deconvolution results. This response is similar to that observed in the lean gas condensate composite reservoirs reviewed in Chapter 2 (Fig. 2-2).

Comparison of the two cases reveals the similarity between a two- and three-zone radial composite region that exists in a lean gas condensate well test and also in our well tests of the tight, dry gas sand formations after fracturing (Fig. 1-2 and Fig. 2-2).

Analytical radial composite match of the well tests is available in Appendix B.

![Figure 3-30. Comparison of pressure derivative curves from well tests performed on each of the four different layers in Well GF-2 after stimulation or fracturing.](image-url)
3.11.1 Well BH-6 extended test
Well BH-6 is located 150 km south of the study well (Well GF-2) and is drilled in a separate, different structure (Fig. 3-1). Similar to Well GF-2, it also penetrates a tight sandstone Ordovician reservoir (QH), which is similar in reservoir character to the tested zones in the study well. As a control and for comparison with the Well GF-2 test results, test data from an extended post-fracturing formation test (1200-hour test) performed on this distant well are shown in Fig. 3-31 and Fig. 3-32. Review of the log-log plot of buildup data from Well BH-6 (Fig. 3-32) shows a bilinear fracture flow response followed by two-zone composite behaviour.

![Simulation (Constant Skin) - Flow Period 2](image)

**Figure 3-31.** Pressure history of extended test in Well BH-6.
3.11.2 Well BH-6 test results
The bilinear fracture flow response (1/4 slope) followed by a two- or three-zone composite behaviour is similar to that observed in the post-fracturing production tests of the Ordovician tight sand reservoirs in Well GF-2 (i.e., a similar anomaly is noted) despite that the wells are separated by 150 km and are in different structures. It is concluded that these responses are not related to geological features because the two wells are distant from each other and in separate structures.

3.12 Primary Direct Investigation—Gauge Resolution
Given that most formation test data available for this study are from tests that exceed 100 hours in most cases, and 1,000 hours in two extended well test cases, it is essential to confirm that the obtained data are not affected by gauge resolution and are a reflection of actual reservoir response.

The methodology used in screening the data is based on the assumption that if \( \frac{\partial p}{2} \) is less than or equal to gauge resolution (where \( p \) is pressure), then the gauge will not have the capacity to measure the signal because error can be positive or negative. Therefore, deviation from actual measurement or some mean value is used to compare with gauge resolution (Fig. 3-33). Thus, for a data scan of 1 second, the gauge can resolve 0.01 psi. Therefore, any pressure
difference equal to or less than 0.01 psi within 1 second of scan time is not a reservoir response but maybe a gauge pressure drift error.

Figure 3-33. Mean scanning of gauge data.

Detailed review of gauge resolution of Test 4 results indicates that the readings are within gauge resolution up to the time point at 2,862,000 seconds (i.e., 795 hours) (Fig. 3-34). In Test 4, the gauge resolution affected the last 7 hours of the buildup period, which lasted 560 hours. However, this had no significant effect on the pressure derivative or the deconvolution results (Fig. 3-35). Thus, it is concluded that the pressure points are a reservoir response and are not affected by gauge resolution effects.

Figure 3-34. Gauge resolution reading endpoint identification.
Figure 3-35. Comparison of original data and gauge-resolution deleted data.

3.13 Primary Direct Investigation—Phase Segregation and PLT Results

It is essential to confirm that the pressure derivative response is reflecting actual reservoir behaviour and not wellbore phase redistribution. Confirmation that the well-test response in our subject case is a result of an actual near- or far-wellbore response, not phase redistribution, can be achieved by substantiating the following points:

- There is no water received on the surface during any of the drawdown periods of the well tests investigated or in the PLT results.
- The downhole temperature is greater than 100°C, because the reservoir temperature is 118°C.
- The same well-test signature profile observed on a DST well-test analysis is also observed on the extended well-test results.

The PLT results are provided in Table 4-2, where $Q$ is the flow rate, and the subscripts $w$, $o$, and $g$ refer to water, oil, and gas, respectively (detailed PLT results are found in Appendices Section A.2, Tables A-1 and A-2).
Table 3-4. Well GF-2 Production Contributions by Phase

<table>
<thead>
<tr>
<th>Formation</th>
<th>Zones, ft</th>
<th>( Q_w ), (scf/d)</th>
<th>( Q_o ), (scf/d)</th>
<th>( Q_g ), (scf/d)</th>
</tr>
</thead>
<tbody>
<tr>
<td>DMK</td>
<td>5692.5-5705.0</td>
<td>0.00</td>
<td>0.00</td>
<td>7441</td>
</tr>
<tr>
<td></td>
<td>5717.8-5725.4</td>
<td>0.00</td>
<td>0.00</td>
<td>5850</td>
</tr>
<tr>
<td></td>
<td>5751.6-5756.5</td>
<td>0.00</td>
<td>0.00</td>
<td>4217</td>
</tr>
<tr>
<td></td>
<td>5768.0-5776.2</td>
<td>0.00</td>
<td>0.00</td>
<td>9266</td>
</tr>
<tr>
<td></td>
<td>5783.4-5787.7</td>
<td>0.00</td>
<td>0.00</td>
<td>13908</td>
</tr>
<tr>
<td></td>
<td>5791.0-5804.7</td>
<td>0.00</td>
<td>0.00</td>
<td>93607</td>
</tr>
<tr>
<td>GEG upper</td>
<td>5955–5987.8</td>
<td>0.00</td>
<td>0.00</td>
<td>16023</td>
</tr>
<tr>
<td>GOS</td>
<td>6972–7008</td>
<td>736</td>
<td>0.00</td>
<td>8345</td>
</tr>
</tbody>
</table>

Note: Downhole rates are interpreted from production log at 24/64-in choke size with a surface rate equal to 6,177,500 ft\(^3\)/d.

The PLT results from Test 2 show that 5% of the total flow came from the GOS formation, 10% came from the GEG formation, and 85% came from the top of the DMK formation, which was previously fracture stimulated. This may be due to tightness of the virgin formation layers. However, more significantly, the PLT results confirm that there is no water flow coming from these reservoir layers.

### 3.14 Other Similar Cases

In addition to the previous detailed case of Well GF-2 and Well BH-6, Dahroug et al. (2013), a further confirmation comes from the occurrence of an identical signature response in well test data from a tight, dry gas field in Canada (Fig. 3-36).

![Figure 3-36. Canadian well test response post fracture stimulation.](image-url)
3.15 Summary

The post-fracturing well test analysis of all four Ordovician reservoir layers (DMK, upper GEG, lower GEG, GOS) in Well GF-2 (a tight, dry gas well) identifies the repetitive occurrence of a two- or three-zone composite model response in the analysis of pressure transient data. A similar response is observed to occur in the analysis of post-fracturing well test data of Well BH-6 (tight, dry gas well with reservoir in the same stratigraphic layer—Ordovician QH formation) located 150 km south of the GF well, in a separate geological structure. A similar case was identified in Canada in post-fracture stimulation well test results, which yielded an identical pressure derivative response. Production log data from Well GF-2 (Test 2; Table 3-4) demonstrates that only a gas phase is present.

The well test response after stimulation in the tight, dry gas reservoirs (i.e., Tests 4, 5, and 6 in Fig. 3-30) is strikingly similar to that observed in wells that have a two- or three-composite zone response associated with the development of a condensate bank. This is based on the following information, which is derived from analysis of actual field data:

- PVT composition of the gas in Well GF-2 shows that 86% of the gas is C1. Thus, the dry gas reservoir is above the dewpoint, with no heavy components.

- It has been highlighted that a composite model response occurs in several wells that penetrate tight reservoir formations, despite their location in different geological structures and different areas. Thus it is concluded that the observed well test response is not related to a specific geological feature.

- Analysis of the production during the flow periods in the study wells and the PLT results do not show any water content. Thus it is concluded that the response is not the result of phase redistribution.

- Tests 3, 4, 5, and 6 in Well GF-2, and the test in Well BH-6, are single-layer tests. Thus it is concluded that the response is not a layered-reservoir response; this was also confirmed with the petrophysical interpretation (Fig. 3-37).

- The gauge resolution data points cover the full test period with minor error. Thus, the data reflect actual reservoir response and are not affected by gauge resolution error.
Figure 3-37. Comparison log-log plot of data from tests 4 to 6 in Well GF-2 and the extended well test in Well BH-6.

It has been concluded that a full match of the entire test results with the use of the current existing analytical models is not possible, particularly if both the fracture and the far-wellbore region is considered.

Because more than one analytical model can fit any data, the analytical approach to well test analysis cannot provide a unique solution (Appendix B). The use of deconvolution in well test analysis may help to identify the well model; however, the use of numerical 3D analysis is considered the current optimal technique that can be used for proper reservoir description.

The tightness of the virgin reservoir and the response to fracturing in tight formations will be investigated with further numerical modelling to confirm the behaviour and the sensitivity of parameters to induced fractures.
Chapter 4
Results of Finite-Difference Simulation (Numerical)

4.1 Introduction
From the preceding review (Chapter 3) of the analytical analysis of the actual well test data, it was concluded that the well response exhibits a radial composite behaviour. This implies that the well is located in the middle of radial zones of different permeabilities.

Whereas the analytical methods still represent an essential step toward the understanding of reservoir behaviour in the far-wellbore region, the current available analytical reservoir models may not be the only means by which to derive actual reservoir characterisation. Several studies have confirmed the necessity for integration of other factors to reduce the uncertainties related to analytical well test interpretation, such as the use of geological descriptions, seismic data, and field structure data. The use of numerical models for well test analysis i.e.; numerical well testing, has become an essential step for proper transient well test analysis.

The advantage of numerical simulation is that saturation, effective permeability, and gas mobility can be simulated as functions of radial distance from the well. The ability to use compositional simulation is an essential tool for verifying the difference between a geological feature and features that are a result of complex fluid dynamics of gas reservoirs. The application of numerical simulation is now the industry standard that is used to guide, design, and confirm the interpretation of well tests in complex reservoirs.

In this chapter, I attempt to model the well test transient pressure response by construction of two different numerical models with two finite-difference simulators. The purpose is to confirm observed behaviour with the numerical method, using a 3D finite-difference simulator as a secondary step to confirm the concept of the multiple regions of permeability obtained from the analytical method.

The first modelling attempt uses the ECLIPSE industry-reference reservoir simulator to model and match the actual field response as a radial composite model (i.e., a well with different permeability regions surrounding the well). The purpose is to determine the radius of each region and to match the analytical well test analysis results. A second model is constructed using the tNavigator software, and the purpose is also to match the well test response, but a random fracture network is created in the model by application of different permeability grid
cells around the well in an attempt to verify if the same well test response can be obtained by a different modelling technique.

4.2 Finite-Difference Simulation—Dynamic Model Description of ECLIPSE Setup

A single-well model consisting of $55 \times 87 \times 20$ cells was made. Porosity and permeability values were input as per the core analysis data and petrophysical data of the well. To match the tightness of the formation layer, the permeability was obtained from well test interpretation and is very low, 0.1 mD. Three different zones were mapped around the wellbore to match the radial composite response observed in the actual well test analysis (Fig. 4-1). Two simulation models were constructed—one in black oil and one in compositional fluids.

![Model with composite regions around subject well, GF-2.](image)

4.2.1 Fluid model and saturation functions

One black oil fluid model and one composition fluid model were used in the simulations. A set of saturation functions (relative permeability, capillary pressure, and rock compaction) was derived from empirical correlations.
4.2.2 Well completions
The designed model included a completion identical to Well GF-2, with a perforation interval from 6133 to 6166 ft MD, representing the lower GEG formation (Test 4) and with the incorporation of a hydraulic fracture.

4.2.3 Simulation periods
The simulation periods used for all simulations were the same as the drawdown and shut-in periods of the actual well test: constant flow rate to simulate the drawdown, followed by a zero flow rate to simulate the buildup.

4.2.4 History matching parameters
The purpose is to history match the bottomhole pressure while respecting some constraints. Permeability and initial reservoir pressure remain unchanged. The following parameters were used for the hydraulic fracture: width = 21.65 ft, length = 785.8 ft, and orientation = 70° (Fig. 4-2).

![Figure 4-2. Match of actual well test pressure history and simulated well test data.](image-url)
4.2.5 Simulation results

A match to Test 4 was obtained in both the black oil and the compositional models (Fig. 4-3).

![Figure 4-3. Comparison of actual well test log-log plots and simulated model results.](image)

**Figure 4-3. Comparison of actual well test log-log plots and simulated model results.**

4.2.6 Effect of water saturation

Changes in the water saturation endpoints were made to see the effect on the well test results (Fig. 4-4). The two comparison values below and above the endpoints produced minor effects on the late-time region response (Fig. 4-5).

Figure 4-5 compares the well test simulation results of the match between the actual and simulated well test results, a suitable match is obtained and changes in the water saturation affects the late-time region only.
Figure 4-4. Water saturation endpoint values synthesis.

Figure 4-5. Results of well test simulated results with the compositional model.
4.3 Finite-Difference Simulation—Setup
A base model was constructed with a single well at the centre. The characteristics of the model are listed in Table 4-1.

<table>
<thead>
<tr>
<th>Reservoir Characteristic</th>
<th>Value</th>
</tr>
</thead>
<tbody>
<tr>
<td>No. of grid blocks</td>
<td>( Dx = 100, Dy = 100, Dz = 20 )</td>
</tr>
<tr>
<td>Grid block size (ft)</td>
<td>( X = 492, Y = 492, Z = 59 )</td>
</tr>
<tr>
<td>Net/Gross</td>
<td>Max. = 1, Min. = 0</td>
</tr>
<tr>
<td>Effective porosity</td>
<td>Max. = 0.1182, Min. = 0</td>
</tr>
<tr>
<td>SWAT (water saturation)</td>
<td>Max. = 1, Min. = 0</td>
</tr>
<tr>
<td>PERMX</td>
<td>Max. = 1, Min. = 0.01</td>
</tr>
<tr>
<td>PERMZ</td>
<td>Max. = 0.1, Min. = 0</td>
</tr>
<tr>
<td>Thickness ((h)), (ft)</td>
<td>32.8</td>
</tr>
<tr>
<td>Initial pressure ((p_i)), psi</td>
<td>3091.3 psia</td>
</tr>
<tr>
<td>Temperature, °F</td>
<td>212</td>
</tr>
</tbody>
</table>

The model included a completion identical to the Well GF-2 perforation interval at 5695.8–5787.7 ft MD representing the DMK formation (Test 6), with the incorporation of a planar hydraulic fracture filled with different proppant (Fig. 4-6).

Figure 4-6. Planar fracture induced in finite-difference tNavigator model.
4.3.1 Finite-difference simulation results

Two single-well models were constructed to numerically model the conceptual assumptions made. The first model (Model A) depicts a single non-fractured well in a tight, naturally fractured formation (Fig. 4-7 and Fig. 4-8). The second model (Model B) depicts a fractured well with a distinct distribution of natural fractures that are oriented perpendicular to the induced fracture (Fig. 4-9 and Fig. 4-10).

![Figure 4-7. Initial Model A set up.](image)

![Figure 4-8. Derivative of Model A set up.](image)
Figure 4-9. Conceptual Model B setup.

Figure 4-10. Conceptual Model B match comparison.

The derivative curve of Model A (Fig 4-8) corresponds to that of a typical tight formation. A close match is obtained with the conceptual model (Fig. 4-10), which does confirm the conceptual model assumptions using the finite-difference method.
4.4 Proof-of-Concept Simulation—Composite Model Results

The well test analysis of the analytical radial composite model is presented in Appendix B. Numerical reservoir simulation using finite-difference methods was performed to confirm the applicability of the analytical method, and has shown that the match of the actual well test data is achieved by the use of three different regions of permeability around the wellbore and the induced hydraulic fracture. Below we review the pressure history plot of Test 4 (Fig. 4-11) and the analytical model match for Test 4 (Fig. 4-12) as an example.

![Simulation (Constant Skin) - Flow Period 1207](image)

**Figure 4-11. Pressure history plot for Test 4.**

![Log-Log Match - Flow Period 1207](image)

**Figure 4-12. Log-log plot with analytical model match to radial composite model of Test 4.**
4.5 Discussion

Numerical simulation was performed using different numerical simulation models to attempt to confirm and investigate the well test analytical model presented in the preceding chapter. The match obtained between a radial composite analytical method and numerical simulation provides confirmation that different regions of permeability exist around the wellbore of post-fractured tight sandstone reservoirs; however, it does not explain why this change in permeability exists.

While a suitable match was obtained using the finite-difference method, additional simulation modelling using the finite-element method is required to expand our ability to test the hypothesis made in our direct problem approach and explain the anomaly seen in the interpretation in the tight gas reservoir. The following is required for this process:

- The use of fracture modelling to enable simulations in finite-element simulators
- An understanding of the sensitivity of the fracture aperture and natural fracture network complexity.

The goal is to investigate the effect of the hydraulically induced fracture on the near-wellbore area adjacent to the induced fracture, on the far-wellbore area beyond the induced fracture, and on the naturally existing fracture network. Once that has been achieved, further investigation will be performed to identify the characteristics of the induced fracture (i.e., fracture length, aperture, porosity, and permeability) and critical stress of the adjacent zones.

Verification and interpretation of the available data was performed. The uniqueness of the anomaly was proven and validated to be repetitive. This justified further investigation related to the actual behaviour of gas fluid flow in tight sandstone and fracture networks post fracturing in a more comprehensive manner with the use of finite-element simulation methods.
Chapter 5
Hypothesis A and B Results of Finite-Element Simulation

5.1 Introduction
The recent trend of finite-element simulation techniques has improved the capture of complex geological detail and can combine several reservoir characteristics without the need for numerous grid counts. The main advantage is the avoidance of simulation errors of pressure and saturation that are essential to maintain the accuracy with minimum grid count and simulation time. Numerical dispersion errors that may occur due to upscaling and inaccurate grid size are substantially avoided by the averaging process.

The use of unstructured meshes rather than the traditional cube grids is a great advantage, allowing the simulation of discrete fracture networks (DFNs) and complex fracture networks that intersect with the matrix rock. In tight sandstone reservoirs, the permeability of the matrix is typically very low, whereas the permeability of the natural fractures is very high. The use of the averaging scheme of finite-element simulation in a bilinear fashion (averaging between two nodes) enables the capture of the full permeability and the flow spectra in the reservoir, as compared to upscaling both the fracture and the grid permeability in a single grid block, which would overestimate the permeability and flow capability in the reservoir.

In this chapter, finite-element simulations are used to test the proposed hypothesis and investigate how the well test analysis results are affected by the different fracture properties, such as fracture orientation, fracture shape factor (sides), and quantify their effect on the well test analysis early-, middle-, and late-time regions.

The proposed hypothesis is then implemented by insertion of a DFN in a homogenous property grid model. Changes are implemented on the DFN properties in terms of the fracture properties to be able to mimic the proposed hypothesis, and the simulation results are compared in terms of the transient pressure analysis of a simulated well test.
5.2 Simulation Methodology

Modelling of fracture networks is a complex task because the fractures typically have very different intensity, orientation, length, transmissibility, and apertures; in addition, they intersect with each other, and the flow from the matrix into the fracture varies. Thus upscaling is an essential technique to convert the complex DFN into properties that can be run as dual-porosity or dual-permeability simulations that can be achieved in an adequate time scale.

Petrel simulation software was used to initiate the base model grid with its typical reservoir properties as obtained from the core analysis data. The DFN was then implemented on different regions around the well and the induced hydraulic fracture. The fracture set was then incorporated and upscaled in the finite-element model using the Oda method (a geometry-based method used to upscale permeability tensors that are initially in a DFN).

The advantage of the Oda method is that it provides fast simulation without requiring flow simulation. The disadvantage is that it does not account for the fracture connectivity and its length; however, in our subject simulation, the fractures are typically well connected via the induced hydraulic fracture.

Primarily, validation of the effect of the DFN on well test results is needed, so a model was set up with homogeneous properties and DFN density (P32), and then synthesis on different fracture properties was performed.

The proposed hypotheses A and B were then tested, as outlined in the problem and approach sections (Sections 1.2 and 1.3) in Chapter 1. The different hypotheses are implemented by applying changes to the DFN properties, such as changes in fracture intensity or aperture (Fig. 5-1).

![Flowchart Image]

Figure 5-1. Description of the DFN simulation process.
5.3 Synthesis of DFN Properties on Well Test Results

5.3.1 Model setup with homogeneous DFN distribution

A base model was set up with a homogeneous DFN (i.e., constant fracture network with no changes in fracture intensity in and around the regions of the well) and the induced hydraulic fracture, with scholastic distribution of fractures based on the Fisher model (Fig. 5-2). Table 5-1 and 5-2 describe the properties of the base model and the DFN.

![Figure 5-2. Region dimensions of the base model and the DFN.](image)

<table>
<thead>
<tr>
<th>Table 5-1. Model Properties</th>
</tr>
</thead>
<tbody>
<tr>
<td>Grid cells</td>
</tr>
<tr>
<td>I direction</td>
</tr>
<tr>
<td>J direction</td>
</tr>
<tr>
<td>K direction</td>
</tr>
<tr>
<td>Total number of cells</td>
</tr>
<tr>
<td>Permeability, mD</td>
</tr>
<tr>
<td>Porosity, %</td>
</tr>
</tbody>
</table>

<table>
<thead>
<tr>
<th>Table 5-2. DFN Properties</th>
</tr>
</thead>
<tbody>
<tr>
<td>Geometry</td>
</tr>
<tr>
<td>Number of sides</td>
</tr>
<tr>
<td>Elongation ratio</td>
</tr>
<tr>
<td>Length (mean)</td>
</tr>
<tr>
<td>Max. length of implicit fractures</td>
</tr>
</tbody>
</table>

<table>
<thead>
<tr>
<th>Orientation</th>
</tr>
</thead>
<tbody>
<tr>
<td>Mean dip azimuth</td>
</tr>
</tbody>
</table>
The model was validated by applying small timesteps in the very-near-wellbore region only that were limited to grid refinement in the first four adjacent grid blocks of the model, only, to prevent any numerical artefact from affecting the actual results.

### 5.3.2 Sensitivity study of the orientation

The preceding base model had fracture orientation of 0 degrees, which is parallel to the direction of the induced fracture. The sensitivity study was based on the orientation of fractures being within the range of 0 degrees to 90 degrees (Fig. 5-3); all other DFN properties remained unchanged.

![Base Case 90 degrees](image1)

![Case 0 degrees](image2)

**Figure 5-3.** Comparison between the vertical- and horizontal-oriented DFN. Single sample fractures are displayed outside the model to identify the difference in orientation.

Figure 5-4 shows a comparison of the actual well test response illustrated in the transient pressure analysis of the green curve, with the brown curve, which is the simulation of the same DFN model with the fractures oriented at 90 degrees (i.e., perpendicular to the induced hydraulic fracture). The purple curve is the well test simulation result of the same model with fractures oriented at 0 degrees (i.e., parallel to the induced hydraulic fracture). It is seen that there is a significant change in the pressure derivative due to the low drawdown, which results in much higher productivity because more natural fractures are intersecting the induced hydraulic fracture, thus the flow path to the wellbore is denser. The blue curve reflects well test simulation results of the fracture network oriented at 45 degrees to the induced hydraulic fracture—an intermediate result is obtained.

Figure 5-5 compares the pressure history of the simulation of 0-, 45-, and 90-degree fracture orientation. It is obvious that in the case of the 0-degree fracture orientation, the pressure match
of the buildup is close to the actual data; the drawdown is low due to the easy flow toward the wellbore. In the case of the 90-degree fracture orientation (brown curve in Fig. 5-5), the high drawdown is due to the diversion of the flow direction toward the wellbore.

![Figure 5-4. Comparison of pressure history of well test simulation results of models with 0- and 90-degree DFN orientation.](image)

![Figure 5-5. Log-log plot showing comparison of well test simulation results of models with 0-, 45-, and 90-degree DFN orientation.](image)
5.3.3 Sensitivity study of the shape factor

Using the same base model, changes were applied to the fracture shape factor, which is sensitized by changing the elongation factor; all other DFN properties remained unchanged (Fig. 5-6).

Figure 5-6. Comparison between base case and model with elongation factor of 100. Single sample fractures are displayed outside the model to identify the difference in shape factor.

Figure 5-7 shows a comparison of the well test simulation results of a model with elongation factor of 100 versus the base case.

Figure 5-7. Comparison plot of well test response of base case and model with elongation factor of 100.
The elongation is the main parameter that has an effect on the well test results. This is expected because, as the elongation ratio increased to 100 (as compared to the base case of 1) (i.e., a square-shaped fracture), the distance between each fracture (as well as the distance between the fracture sets) and the induced hydraulic fracture increases, resulting in a reduction of permeability.

Further confirmation of the preceding results was achieved by the well test simulation results of a model with an elongation factor of 0.0001 (Fig. 5-8).

![Figure 5-8](image)

**Figure 5-8.** Comparison between base case and model with elongation factor of 0.0001. Single sample fractures are displayed outside the model to identify the difference in shape factor.

A further improvement of permeability is noted in the log-log plot comparison in Fig. 5-9.

![Figure 5-9](image)

**Figure 5-9.** Comparison of the effect of the fracture elongation factor on WT-simulated results.
5.3.4 Sensitivity of the number of sides

Using the same base model, changes were made to the number of sides of the fractures that make up the DFN; all other DFN properties remain unchanged. Figure 5-10 compares the different shape factors of the fracture, and Fig. 5-11 shows the well test results.

Figure 5-11 illustrates that while the shape factor (i.e., number of sides) does have an effect on the well test results, this effect is still minor with respect to permeability; it corresponds to 8% in the late-time region. The effect of the elongation factor—up to 25% change in well test results—is greater than the effect due to change in the shape or number of sides.

Figure 5-10. Change of the number of sides of each fracture from 4 to 10. Single sample fractures are displayed outside the model to identify the difference in the number of sides.
5.4 Simulation of Hypotheses

With reference to the hypotheses outlined in Chapter 1, Section 1.2 and 1.3 of this report, two possible hypotheses were tested that could be related to the styles of connectivity addressed by Jolly and Cosgrove (2003, Fig. 1-4) and the actual well test derivative in Fig. 1-1 and Fig. 1-2.

To test Hypothesis A, in which a crushed or compacted zone exists around the fracture and causes permeability degradation, a DFN model with multiple zones around the fracture was used with implementation of varying fracture density with fixed fracture aperture around the well.

To test Hypothesis B, in which the nature of flow across the natural fracture network beyond the induced hydraulic fracture is related to whether the fractures may or may not intersect the induced hydraulic fracture and/or each other, a DFN model with multiple zones around the fracture was used with implementation of a varying fracture aperture with fixed matrix permeability and fixed fracture density.

5.4.1 Hypothesis A—Varying fracture density and fixed fracture aperture

To test this hypothesis, a model with the well in the centre of five regions with the same matrix permeability and porosity was set up as follows: matrix \( k_x = 0.01, k_y = 0.01, k_z = 0.1 \); matrix \( \phi = 0.05 \). Figure 5-12 illustrates the five DFN regions (regions 4–8) surrounding the well. The fracture networks within the regions were designed with different fracture intensity and

![Figure 5-11. Comparison of the effect of the number of sides of the fracture on WT-simulated results.](image)
permeability as shown in Table 5-3. Illustrations of the model and fracture sets are shown in Figs. 5-13 to 5-17.

Figure 5-12. Set up of different DFN regions around the well.

<table>
<thead>
<tr>
<th>Region</th>
<th>P32</th>
<th>Max Length of Implicit Fracture (ft)</th>
<th>Mean Dip Azimuth (°)</th>
<th>Aperture Mean</th>
<th>Aperture Std Dev.</th>
<th>Perm (mD)</th>
</tr>
</thead>
<tbody>
<tr>
<td>Region 4</td>
<td>0.0001</td>
<td>26.25</td>
<td>0</td>
<td>0.000075</td>
<td>0.0000015</td>
<td>500</td>
</tr>
<tr>
<td>Region 5</td>
<td>0.001</td>
<td>26.25</td>
<td>90</td>
<td>0.000075</td>
<td>0.0000015</td>
<td>3000</td>
</tr>
<tr>
<td>Region 6</td>
<td>0.01</td>
<td>26.25</td>
<td>0</td>
<td>0.000075</td>
<td>0.0000015</td>
<td>5000</td>
</tr>
<tr>
<td>Region 7</td>
<td>0.01</td>
<td>26.25</td>
<td>90</td>
<td>0.000075</td>
<td>0.0000015</td>
<td>7000</td>
</tr>
<tr>
<td>Region 8</td>
<td>0.001</td>
<td>26.25</td>
<td>0</td>
<td>0.000075</td>
<td>0.0000015</td>
<td>9000</td>
</tr>
</tbody>
</table>
Figure 5-13. Fracture sets set up within regions.

Figure 5-14. Fracture intensity P32 setup.
Figure 5-15. Fracture aperture illustration.

Figure 5-16. Fracture permeability illustration.
Simulations were based on the Oda finite-element method. From the simulation of the preceding model, the results show deflections in the well test derivative curve related to fracture intensity and permeability (Fig. 5-18).
Thus it proves that in a model with homogeneous matrix porosity and permeability, the variations in the well test derivative curve are the result of different fracture sets with different fracture intensity and fracture permeability around the well.

In Fig. 5-19, the green curve represents the actual well test data; the brown curve represents the simulated model results based on the modelled fracture network intensity. The brown curve is similar to the deconvolution results discussed in Chapter 3.

![Graph](image.png)

**Figure 5-19. Comparison of the actual well test data and the model simulation results.**

### 5.4.2 Hypothesis B—Varying fracture aperture, fixed $k_m$ (matrix perm), fixed fracture density, P32

Using the same model previously described, changes were implemented in the fracture aperture while keeping the matrix permeability ($k_m$) and matrix fracture density constant; all other variables were constant (Table 5-4). The increased fracture apertures were implemented in the different regions around the well and the induced fracture had a relatively high aperture of 0.295 inch in the outermost regions.

Starting with the outermost region, changes were applied to regions 7 and 8 as per the following simulations, with changes in the fracture aperture value (Tables 5-5 to 5-8).
### Table 5-4. Fracture Characteristics of Model To Test Hypothesis B

<table>
<thead>
<tr>
<th>Fracture Set</th>
<th>Region</th>
<th>P32</th>
<th>Mean Dip Azimuth (°)</th>
<th>Aperture Std Dev.</th>
</tr>
</thead>
<tbody>
<tr>
<td>1</td>
<td>Region 4</td>
<td>0.01</td>
<td>0</td>
<td>0.0000015</td>
</tr>
<tr>
<td>2</td>
<td>Region 5</td>
<td>0.01</td>
<td>0</td>
<td>0.0000015</td>
</tr>
<tr>
<td>3</td>
<td>Region 6</td>
<td>0.01</td>
<td>0</td>
<td>0.0000015</td>
</tr>
<tr>
<td>4</td>
<td>Region 6</td>
<td>0.01</td>
<td>90</td>
<td>0.0000015</td>
</tr>
<tr>
<td>5</td>
<td>Region 7</td>
<td>0.01</td>
<td>0</td>
<td>0.0000015</td>
</tr>
<tr>
<td>6</td>
<td>Region 7</td>
<td>0.01</td>
<td>90</td>
<td>0.0000015</td>
</tr>
<tr>
<td>7</td>
<td>Region 8</td>
<td>0.01</td>
<td>0</td>
<td>0.0000015</td>
</tr>
<tr>
<td>8</td>
<td>Region 8</td>
<td>0.01</td>
<td>90</td>
<td>0.0000015</td>
</tr>
</tbody>
</table>

### Table 5-5. HB1_MOD16

<table>
<thead>
<tr>
<th>Fracture Set</th>
<th>Region</th>
<th>Aperture Mean (in)</th>
</tr>
</thead>
<tbody>
<tr>
<td>1</td>
<td>Region 4</td>
<td>0.002955</td>
</tr>
<tr>
<td>2</td>
<td>Region 5</td>
<td>0.02955</td>
</tr>
<tr>
<td>3</td>
<td>Region 6</td>
<td>0.2364</td>
</tr>
<tr>
<td>4</td>
<td>Region 6</td>
<td>0.2364</td>
</tr>
<tr>
<td>5</td>
<td>Region 7</td>
<td>3.152</td>
</tr>
<tr>
<td>6</td>
<td>Region 7</td>
<td>3.152</td>
</tr>
<tr>
<td>7</td>
<td>Region 8</td>
<td>3.152</td>
</tr>
<tr>
<td>8</td>
<td>Region 8</td>
<td>3.152</td>
</tr>
</tbody>
</table>

### Table 5-6. HB1_MOD17

<table>
<thead>
<tr>
<th>Fracture Set</th>
<th>Region</th>
<th>Aperture Mean (in)</th>
</tr>
</thead>
<tbody>
<tr>
<td>1</td>
<td>Region 4</td>
<td>0.00075</td>
</tr>
<tr>
<td>2</td>
<td>Region 5</td>
<td>0.02955</td>
</tr>
<tr>
<td>3</td>
<td>Region 6</td>
<td>0.2364</td>
</tr>
<tr>
<td>4</td>
<td>Region 7</td>
<td>2.955</td>
</tr>
<tr>
<td>5</td>
<td>Region 8</td>
<td>2.955</td>
</tr>
<tr>
<td>6</td>
<td>Region 8</td>
<td>2.955</td>
</tr>
</tbody>
</table>

### Table 5-7. HB1_MOD7

<table>
<thead>
<tr>
<th>Fracture Set</th>
<th>Region</th>
<th>Aperture Mean (in)</th>
</tr>
</thead>
<tbody>
<tr>
<td>1</td>
<td>Region 4</td>
<td>0.002955</td>
</tr>
<tr>
<td>2</td>
<td>Region 5</td>
<td>0.02955</td>
</tr>
<tr>
<td>3</td>
<td>Region 6</td>
<td>0.2364</td>
</tr>
<tr>
<td>4</td>
<td>Region 6</td>
<td>0.2364</td>
</tr>
<tr>
<td>5</td>
<td>Region 7</td>
<td>0.3152</td>
</tr>
<tr>
<td>6</td>
<td>Region 7</td>
<td>0.3152</td>
</tr>
<tr>
<td>7</td>
<td>Region 8</td>
<td>0.3152</td>
</tr>
<tr>
<td>8</td>
<td>Region 8</td>
<td>0.3152</td>
</tr>
</tbody>
</table>

### Table 5-8. HB1_MOD14

<table>
<thead>
<tr>
<th>Fracture Set</th>
<th>Region</th>
<th>Aperture Mean (in)</th>
</tr>
</thead>
<tbody>
<tr>
<td>1</td>
<td>Region 4</td>
<td>0.02955</td>
</tr>
<tr>
<td>2</td>
<td>Region 5</td>
<td>0.2955</td>
</tr>
<tr>
<td>3</td>
<td>Region 6</td>
<td>0.2364</td>
</tr>
<tr>
<td>4</td>
<td>Region 7</td>
<td>0.2364</td>
</tr>
<tr>
<td>5</td>
<td>Region 7</td>
<td>0.2955</td>
</tr>
<tr>
<td>6</td>
<td>Region 8</td>
<td>0.2955</td>
</tr>
<tr>
<td>7</td>
<td>Region 8</td>
<td>0.2955</td>
</tr>
<tr>
<td>8</td>
<td>Region 8</td>
<td>0.2955</td>
</tr>
</tbody>
</table>
It is noted in Fig. 5-20 that the lower apertures in HBMOD 16 and 17 are reflected as a steeper decline in the late-time region of the well test response; a lower aperture is reflected as a less steep decline in the late-time region.

Figure 5-20. Comparison of the actual well test data and different DFN aperture simulations of the outer region (Region 7).
The changes shown in Figs. 5-21 and 5-22 and Tables 5-9 and 5-10 were implemented in Region 7 only.

Figure 5-21. DFN aperture of Region 7.

Figure 5-22. DFN aperture of Region 6.
Figure 5-23. Comparison of well test simulation results of different DFN aperture in Region 7.

Figure 5-23 compares the results of HB18, which had aperture of 0.0006 in regions 7 and 8, to HB24 that had an aperture of 0.00075 in Region 7 and an aperture of 0.0006 in Region 8. Note the difference in the late-time derivative, moving up toward a lower-permeability response.
Changes to the fracture network were implemented in Region 6 according to Fig. 5-24 and Table 5-11. Figure 5-25 illustrates a response that matches close to the actual well test data. Thus it proves a positive indicator that the fracture sets in Region 6 that are close to the induced fracture are actually of a higher aperture value than the aperture sets in regions 7 and 8 that are located away from the induced hydraulic fracture.

![Figure 5-24. HB1_MOD36DFN with different apertures in regions 6, 7, and 8.](image)

<table>
<thead>
<tr>
<th>Fracture Set</th>
<th>Region</th>
<th>Aperture Mean (in)</th>
</tr>
</thead>
<tbody>
<tr>
<td>1</td>
<td>Region 4</td>
<td>0.002955</td>
</tr>
<tr>
<td>2</td>
<td>Region 5</td>
<td>0.02955</td>
</tr>
<tr>
<td>3</td>
<td>Region 6</td>
<td>0.2364</td>
</tr>
<tr>
<td>4</td>
<td>Region 7</td>
<td>0.02955</td>
</tr>
<tr>
<td>5</td>
<td>Region 8</td>
<td>0.0197</td>
</tr>
<tr>
<td>6</td>
<td>Region 6</td>
<td>0.2364</td>
</tr>
<tr>
<td>7</td>
<td>Region 7</td>
<td>0.02955</td>
</tr>
<tr>
<td>8</td>
<td>Region 8</td>
<td>0.0197</td>
</tr>
</tbody>
</table>
Figure 5-25. Comparison of well test simulation results of different DFN of aperture of regions 6, 7, and 8.

5.5 Results
The finite-element simulation implemented using DFN network sets to test the initially proposed hypotheses may provide an explanation of the well test behaviour that was seen and provides insight that the well test behaviour is due to changes in DFN properties. It has been shown that the changing of fracture density, permeability, and aperture has a direct change of anisotropy, which reflects a change in permeability on the well test response.

The region on the outer area of the induced hydraulic fracture (denoted as Region 6 in the previous model and corresponding to Zone 3 in Figs. 1-1 and 1-2) is the area most affected by the change in aperture.

5.6 Discussion
Changes in the fracture orientation, fracture shape, and aperture do have a direct influence on the change of permeability and this has been proven by simulation results and well test analysis.

The results of the hypothesis investigation do show that changes in the fracture intensity and fracture properties impact the well test analysis. While the obtained results are significant to confirm that the changes in the properties of the DFN network in tight sandstone formations can produce significant changes in the well test derivative of these reservoirs, it is difficult to
confirm that one particular hypothesis is definitively proven. Other factors need to be investigated that will support one or a combination of these hypotheses.

The sensitivity study concludes that the change of the fracture aperture, and fracture intensity P32 is basically a change of anisotropy, which is similar to the typical description of a radial composite model, which reflects a change of permeability in the analytical or numerical simulation techniques.

The fracture shape factor and the fracture orientation have a significant effect on the flow profile but do not produce a change of permeability that is identical to the typical radial composite model.

In essence, the simulation results support the conclusions that the fracture shape factor and the fracture orientation do have an effect on the flow profile in naturally fractured reservoirs post fracturing. Our previous finite-element simulations of the composite model did not account for the geomechanical effect that may be producing the observed well test behaviour.
Chapter 6
Hypothesis C—Results of Finite-Element Geomechanical Numerical Simulation

6.1 Introduction
The implementation of the well test procedure involves flow of the well followed by shut-in of the well to induce a transient pressure response in the reservoir. This typically has an effect on the dynamic change of pressure in the near-wellbore area of the reservoir. Consequently, this will in turn have an effect on the 3D effective stress state and stress path and will produce changes in the deviatoric stresses (stresses that actually cause distortion), which may cause permeability changes. Permeability changes that are induced due to changes in the geomechanical status of the well during the well test may be misinterpreted and inappropriately used to interpret characterisations in the near and far regions of the reservoir.

To account for these geomechanical effects and evaluate their impact, a stress-sensitive simulator that couples fluid flow and the geomechanical effect was chosen. The coupling is achieved by combining the ECLIPSE finite-difference simulator with the VISAGE finite-element geomechanics simulator (geomechanical stress simulator) that formulates nonlinear finite-element modelling of the geomechanical effects induced by reservoir production and their influence on fluid flow in the reservoir.

To detect the effect of the induced hydraulic fracture on tight reservoirs with pre-existing complex fracture networks, there is a need to simulate the response of the well test prior to inducing the hydraulic fracture. The DFN is modelled so as to match the initial well test response. Then the hydraulic fracture is induced with the same actual injection parameters that were used during the fracturing operation. Interpretation is made by comparing results prior to and post creation of the induced hydraulic fracture, taking into account the effect of the induced hydraulic fracture on the tight reservoir formation. In addition, the geomechanical effect of the induced fracture is considered by using the initial actual geomechanical formation properties and the geomechanical effect post fracturing. Thus, the effect of the DFN and its geomechanical effect on the well test response can be investigated, and the parameters of the induced hydraulic fracture can be identified.
In this chapter, the numerical model setup for modelling the induced fracture in wells in tight sandstone formations is presented as well as a methodology to compare the different fracture models, and identify key fracture parameters. The induced fracture model was used to investigate the effect of geomechanics on well test results, and then was applied to the actual subject field data.

6.2 Methodology

In order to measure the effect of geomechanics on the DFN and identify the parameters of the induced fracture (e.g., actual fracture conductivity), the initial well test response needs to be matched at the initial pre-fracturing stage, then followed with simulation of the existing induced fracture in the reservoir. As opposed to the current simulation techniques that model the fracture as a change in permeability along an extended plane around the wellbore or as a plane with different permeability zones around the well, the use of a more complex software program models the actual penetration and shape of the fracture as it penetrates the tight sandstone formation. Concurrently, the actual pumping schedule of the gel–mixed proppant and its fluid characteristics are taken into consideration. The rate at which the different stages of the treatment are pumped is addressed in the reservoir simulation, as this may have an effect on the shape and size of the fracture. The simulation modelling includes consideration of shape, size, and the intersections of the induced fracture, and the optimal calibration, providing the capability to measure the effect of the fracture on the DFN. Comparison of the geomechanical stress of the reservoir is compared before and after creation of the induced fracture, thus establishing the ability to quantify the stress effect on the DFN networks. The output of that process is typically reflected in the well test results and its effect on the well test response can be noted, as the DFN will be incorporated within the modelled induced fracture. In essence, this methodology establishes the effect of the induced hydraulic fracture on the near-wellbore geomechanics in the well test response.

The overall model is incorporated into an embedded model, and the geomechanical effect on the DFN in the region surrounding the induced fracture can be measured. This enables quantification of the stress and strain that is induced on the DFN network in the region beyond the induced hydraulic fracture.

The process comprises three stages using two different software programs:

- First, set up a single-well model in the ECLIPSE finite-difference simulator, with a DFN constructed to match the pre-fracturing well test response. This enables the
modelling of a stochastic DFN that matches the actual fracture network pre-existing in
the original reservoir (i.e., the fracture distribution in terms of the fracture area per
volume, fracture length per volume, and fracture count per volume). The geometry is
based on the fracture shape, fracture length, and maximum length of implicit fractures.
Orientation is based on the Fisher model with constant parameters. Aperture is based
on a log normal distribution with constant parameters, and fracture permeability is
correlated to aperture based on the cubic law. The DFN is then upcaled using the finite-
element Oda method, yielding upcaled values of the DFN porosity, sigma factor, and
permeability.

- Secondly, simulate the induced hydraulic fracture using Petrel Mangrove stimulation
design software (hydraulic fracturing simulator). The fracture is induced in the finite-
element stimulation as the proppant and fluid are injected into the formation. Different
fracture propagation shapes are used to model the actual fracture that was induced.
Compare the well test response post fracture with the actual well test response, but
during the early-time region only, as the purpose is to model and match the linear flow
that results from the induced fracture.

- Thirdly, model the geomechanical properties of the formation using VISAGE finite-
element geomechanics simulation software. Using the same homogeneous DFN
network that was used to model the previous cases and with all other parameters
unchanged, assess the geomechanical effect of the permeability change by using
permeability updating functions that relate to the normal and shear strain of the DFN.
The effect on the natural fracture network is used to match the remaining part of the
well test. This is coupled with the finite-difference simulator; in essence, the changes
of permeability encountered due to fluid flow in the reservoir are modelled using the
finite-difference simulator, and that is then used as input to the VISAGE simulator,
which takes the effect of the permeability change and upgrades the geomechanical
properties of the formation for every time step in the finite-element method.

6.3 The Purpose of the Coupling
A fully coupled two-way simulation model is used to define the effect of the geomechanical
stress of the DFN on fluid flow in hydrocarbon reservoirs. This enables the analysis of the
pressure transient that is a result of stress-dependent permeability. The coupled interaction
between the change of stress in the finite-element method and the change of permeability in
the finite-difference method is significant to the investigation of the influence of the stress state on the fluid flow in the reservoir. The results are then displayed as an analytical pressure transient analysis (log-log plot).

This workflow presents an efficient means to model tight sandstone reservoirs that are typically stress sensitive, taking into account the initial geomechanical state prior to the stimulation and then comparing that with the state after inducing the hydraulic fracture, thus assessing the effect of the hydraulic fracture on the DFN.

Initialisation starts with a single ECLIPSE simulation run for one time step; the yielded results of pressure, temperature, and saturation are then input into the VISAGE simulator that provides permeability multipliers, and those results are then fed into the ECLIPSE simulator and a second time step is initiated. This process is continuously repeated until all time steps are simulated and full permeability updating of the matrix, natural fractures, and induced fractures are simulated.

The advantage of this two-way coupling process is that it will reveal the interaction between pressure and permeability change due to deformation in naturally fractured reservoirs. A unique field case is utilised to investigate if the abnormal well test response is related to a geomechanical effect that takes place in the natural fracture network in the reservoir.

Dual-permeability models typically model the natural fracture network as a chain of high-permeability interacting with a relatively lower-permeability matrix. The interaction between both is based on the sigma factor, which may be denoting either high or low interaction between the matrix and the fracture network. However, the actual flow between the fracture network and the matrix is more complex, as some fractures are connected and some are isolated and are usually not uniformly distributed. Even fractures that are not connected and are isolated can still be contributing to the flow via the difference in pressure they exert on the matrix while flowing during production, and they may act as pressure boosters during shut-in. Non-conductive fractures can become conductive when subjected to a different geomechanical stress that will result in fracture opening or closing during production.

6.4 Simulation Workflow
In unconventional tight sandstone reservoirs, the simulated induction of a hydraulic fracture in pre-existing natural fracture networks is very complex, particularly when the proppant distribution along the induced fracture is typically non-homogeneous. To date, there are limited applications that combine the simulation of the fracture introduction into the reservoir and
through the complex pre-existing fracture network together with the simulation of the stress regimes around the fracture and the natural fracture network, while also accounting for the geomechanical properties before and after the induced hydraulic fracture simulation.

The workflow presented in (Fig. 6-1) merges the simulation of fracture propagation and proppant distribution and is based on actual field data of the treatment used to induce the fracture, with the known distribution of a fracture network around the induced fracture and its associated geomechanics. The results of this numerical finite-element simulation are then compared in terms of pressure transient analysis, and the results are compared with actual field data.

The advantages of this workflow are that the induced fracture model takes into account the interaction with the pre-existing natural fractures and the proppant placement as well as the stress shadow effects that are induced around the hydraulic fracture. The workflow is as follows:

- Set up a single-well model with a single DFN homogeneously distributed across the reservoir and match the initial well test prior to creation of the hydraulic fracture. Model the layered reservoir model as a homogeneous tight sandstone formation, with no specific regions defined.
- Induce the hydraulic fracture to match the linear flow profile observed in the early-time region of the well test response post fracturing.
- Define the different regions around the induced hydraulic fracture and use the dynamic geomechanical reservoir simulator to match the middle- and late-time region of the actual well test.
- Compare the changes of geomechanical stress across the reservoir regions around the well with the initial geomechanical properties that were used in the initial model.
- Use the changes of the strain and normal shear as the main parameters to obtain the well test match by using permeability updating functions.
The simulation model used is a single-well cube model designed with reservoir parameters obtained from core data: porosity = 0.1%, reservoir thickness = 91.87 ft (obtained from petrophysical data), and permeability = 0.01 mD. To account for the overburden stress, reservoir depth is 6,102.7 ft, as in the actual field data. Fine grids are used to effectively capture the near-wellbore effects. Table 6-1 provides the dimensions and parameters of the 3D single-well model shown in Fig. 6-2.

<table>
<thead>
<tr>
<th>No. of Cells</th>
<th>Cell X Dimension (ft)</th>
<th>Cell Y Dimension (ft)</th>
<th>Cell Height (ft)</th>
<th>Model Dimensions (ft)</th>
</tr>
</thead>
<tbody>
<tr>
<td>35×35×1</td>
<td>13–436</td>
<td>13–455</td>
<td>92</td>
<td>7218.2×7218.2</td>
</tr>
</tbody>
</table>

Figure 6-1. Suggested simulation workflow.
The model included a DFN with fracture porosity of 2%, fracture permeability that ranged from 0.01 to 500 mD, fracture sigma of 0.005, and the fracture region was extended to 1,640.5 ft. The DFN was upscaled using the finite-element method, and the actual well test duration pre-fracture was simulated (Fig. 6-3). The number of cells was doubled to account for the matrix and fracture (Table 6-2).

<table>
<thead>
<tr>
<th>Table 6-2. Upscaled Single-Well 3D Model</th>
</tr>
</thead>
<tbody>
<tr>
<td>No. of Cells</td>
</tr>
<tr>
<td>--------------</td>
</tr>
<tr>
<td>35×35×2</td>
</tr>
</tbody>
</table>
Figure 6-3. Single-well model with upscaled DFN.
To match the bottomhole pressure data, fracture properties were tuned by controlling the gas production rate (Fig. 6-4).

![Bottom hole pressure graph](image1)

**Figure 6-4. Actual well test flow rate and production data.**

A comparison of results of the actual pre-fracture and the simulated transient well test analysis is shown in Fig. 6-5. From Fig. 6-5, a dual-porosity response is noted in the actual data, which closely matches the modelled pre-fracture response. A high skin value is noted, which is typical for a tight reservoir response pre-fracture. It is noted that the late-time region response is trending toward a lower-permeability zone, which is the area away from the near-wellbore region.
Figure 6-5. Derivative plot of pre-fracture actual data and single-well model simulated well test data.

6.5 Mangrove Simulator

The Petrel Mangrove hydraulic fracturing simulator was chosen to be used because it is capable of simulating induced hydraulic fractures in tight formations with pre-existing natural fractures. It accounts for the propagation of the induced hydraulic fracture in the formation.

The model explicitly simulates hydraulic injection into a fracture network with multiple propagating branches. It accounts for a predefined natural fracture pattern, vertical and lateral variations in stresses, and mechanical rock properties. The model includes stress shadowing effects between fracture branches and near-wellbore effects and accounts for multiple perforation clusters and different fluids, proppant, and flow types. The interaction between hydraulic fractures and pre-existing natural fractures is taken into account by using an analytical crossing model validated against experimental data.

Mirzaei and Cipolla (2012) and Zhou et al. (2012) investigated the different modelling techniques of fracture network simulators, as previously discussed in Chapter 2.
Modelling of tight gas reservoirs post hydraulic fracturing is often very complex due to the inability to detect the typical path of the induced hydraulic fracture growth. Although several microseismic monitoring studies have been performed for prediction of the direction of the hydraulic fracture propagation, the issue still remains uncertain due to the existence of the natural fracture network in and around the well and the induced hydraulic fracture.

To date, induced hydraulic fracture models are typically simulated in numerical models as a bi-wing planar fracture, which is usually mimicked by a series of high-permeability grid cells passing through a reservoir grid of less permeability. However, the correct modelling for the fracture shape and geometry needs to account for the increased storage and surface area as well as the mechanical interaction of the fracture network. The use of the actual pumped schedule and rates is vital in predicting the fracture footprint and its interaction with the natural fracture network. The stress anisotropy (i.e., the difference between maximum and minimum horizontal stresses) has a significant impact on the shape and size of the fracture; this has been proved by microseismic observations as well as by modelling results.

Weng et al. (2011), Gu et al. (2011), and Cipolla et al. (2011), discussed different ways of modelling a proppant-filled induced hydraulic fracture, as previously discussed in Chapter 2.

### 6.6 Hydraulic Fracture Models

In Chapter 2 Section 2.4, we reviewed four different fracture models that can be used to model the induced hydraulic fracture:

- Wire mesh model
- KGD fracture model
- PKN fracture model
- Pseudo three-dimensional (P3D) fracture model.

#### 6.6.1 Wire mesh model

Kresse et al. (2011) introduced a new fracture model that simulates hydraulic injection into a fracture network with multiple propagating branches. It accounts for a predefined natural fracture pattern, vertical and lateral variations in stresses, and mechanical rock properties. Figure 6-6 shows the actual Mangrove simulation of a wire mesh fracture model.
Figure 6-6. Typical shape of the wire mesh fracture model.

### 6.6.2 KGD fracture model

In the KGD model, the fracture widths in vertical planes are coupled through the fluid-flow and continuity equations. Since there is no vertical extension (or fluid flow) in each vertical section, the pressure is uniform; hence, the shape of the fracture is elliptical, resulting in a fracture with a horizontal penetration much larger than the vertical penetration (Fig. 6-7).

Figure 6-7. KGD-simulated fracture shape.
6.6.3 PKN fracture model

Another type of model used to simulate the propagation of a vertical hydraulic fracture was presented by Perkins and Kern (1961) and further improved by Nordgren (1972) by including the variations in flow rate along the fracture (Fig. 6-8). The primary assumption of this model is that the fracture length is greater than the fracture height. Figure 6-8 shows the Mangrove simulation of the PKN fracture model.

Figure 6-8. PKN-simulated fracture shape.

6.6.3 P3D fracture model

The basic concept of the P3D model is the same as in the PKN system (i.e., the vertical planes deform independently, but the height depends on the position along the fracture and time). The major assumption is that the fracture length is greater than the height. Different models have been described in the literature with various assumptions for the height growth.
6.7 Mangrove Application

Mangrove engineered stimulation design software is a specific modelling application that was used to investigate the actual fracture shape and parameters that may occur in tight sandstone reservoirs. The aim of the modelling is to identify the characteristics of the induced fracture, where and how the proppant is distributed and how the natural fracture network is influenced in terms of stresses, and what is the impact on the well test.

The software effectively solves a system of equations governing fracture deformation, height growth, fluid flow, and proppant transport in a complex fracture network with multiple propagating fracture tips.

A DFN model is added to model the physics of fracture interactions, height growth, and stress shadowing and is considered as the upscaling process using the Oda method. The resulting sigma and fracture permeability and porosity are then incorporated in the simulation. The simulation of the fracture penetration and elongation into the reservoir is then taken into consideration. The resulting model is a fracture that incorporates the DFN network around the induced fracture model.

The workflow process primarily outlines the zones of interest in the model, the reservoir fluids, proppant type and properties, completion type, and specifications of the flow path of the treatment fluid.

The treatment path is specified in terms of tubing and casing as well as the perforated interval density, phasing, and stress gradient. The pumping schedule of the treatment is defined in terms of the primary pad stage; the main propped stage; its pumped rate, volume, proppant type and concentration; and slurry volume. An initial 2D DFN is set up around the well, which is then upgraded to a 3D DFN network. The simulation is then set up, taking into consideration the near-wellbore effects that result from the pumping rate and its pressure, the fracture setting in terms of the friction through the perforations, the deviation tortuosity, perforation phasing, and the fracture plane. The purpose of this is to define the treatment path and indicate how the fracturing fluid can be conveyed from the wellhead to the injection points (perforations) for the hydraulic fracture simulation.

The simulation is initiated using the same simple grid previously described, and the proppant friction table is taken into consideration. A production grid is then constructed, taking into consideration a structured gridding type, fracture cell width, unpropped fracture conductivity, fluid stages and pumping schedule, and the treatment design.
The simulation is then performed with the DFN and the induced fracture treatment that is pumped. Thus, the actual simulation induces a fracture into the reservoir layer according to the designed treatments and passes through the same reservoir properties that have been deduced from the core and geomechanical data. The final simulation model also takes into account proppant and erosion due to proppant.

### 6.8 Mangrove Induced Fracture Simulation and Results

The simulation of an induced hydraulic fracture model is divided into two main processes:

- First, to simulate the induced hydraulic fracture as per the actual pumped treatment, a fracture model is generated that incorporates the modelled hydraulic fracture as well as the DFN network around the hydraulic fracture.
- Secondly, a production grid is generated that incorporates the fracture model as well as the larger reservoir model.

There are four options of fracture geometry models that can be used in the tight gas sandstone simulation workflow: the multilayer fracture pseudo three-dimensional (MLF-P3D) model, the P3D model, the PKN model, and the KGD model. The MLF-P3D model should be used if planar fractures are expected and fractures are expected to initiate from multiple perforated regions. The P3D model should be used if planar fractures are expected and fractures are expected to initiate from a single perforated region.

Results of simulations using two different fracture models with the same input model are presented in Figs. 6-9 and 6-10.
Figure 6-9. PKN fracture well test response.

The simulation of a PKN fracture (Fig. 6-9) exhibits a linear flow for an extended period of time of 1 hour. This is typical of flow in a PKN fracture because the PKN model is characterized by a large elliptical area in the vertical direction around the wellbore and linear flow occurs in the fracture due to the large fracture width. The model boundary is thus not seen throughout the simulated test duration.

In the case of a KGD fracture, the results are more applicable to the case of tight sand reservoirs, as seen in the simulation results in Fig. 6-10. The results show a bilinear flow, and the reservoir zone beyond the fracture is seen throughout the same duration of the test as compared to the previous PKN fracture simulation.

The Wire mesh model is typically not applicable for tight reservoirs because it is specifically designed for shale reservoirs. The P3D model is similar in shape to the PKN model and requires multiple reservoir zones, which is not applicable in our case.

It is noted that the KGD fracture model simulation results represented the best match for induced hydraulic fractures in tight formations and will thus be used for the subsequent simulations in the following discussions.
6.8.1 Production grid simulation

The Mangrove software regenerates a new grid (Table 6-3), which is a combination of two grids—primarily the initial production grid and a fracture grid that is incorporated inside of it. The specifics of each grid are as follows:

- The production grid (Fig. 6-11) is considered as a transition grid between the base grid and the fracture grid that is used for further simulation work.

- The fracture grid (Fig. 6-12) is the final grid, which contains a different number of cells because it represents the upscaled version of the fracture and the fracture network around it. It will thus contain discrete regions for each element it represents (i.e., the induced fracture, the unproped induced fracture, and the DFN). So, the fracture grid contains three regions, with relative permeability curves and rock compressibility assigned for each region as well as the associated geomechanical properties (e.g., regions, stress, strains, Poisson’s ratio).

<table>
<thead>
<tr>
<th>No. of Cells</th>
<th>X Dimension (ft)</th>
<th>Y Dimension (ft)</th>
<th>Height (ft)</th>
<th>Model Dimensions (ft)</th>
</tr>
</thead>
<tbody>
<tr>
<td>19×25×3</td>
<td>262.5–6956</td>
<td>262.5–6956</td>
<td>92</td>
<td>7218×7218</td>
</tr>
<tr>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Porosity from 0.05% to 0.092%</td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Permeability from 1 to 2,633 mD</td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
</tbody>
</table>
Figure 6-11. Production model grid.

Figure 6-12. Fracture model within the production grid.
Table 6-4 defines the parameters of the fracture model that were induced by simulation to the production grid. The half-length $X_f$ of the actual fracture, as per the well test analysis, is 80 m; thus here it is noted there is a close match obtained from the well test fracture design and the simulated model of the fracture (Table 6-5). It is noted that 60% of the induced hydraulic fracture is propped and the remaining 40% is unpropped. The 40% of the unpropped section is not evenly distributed; however, a larger proportion of the unpropped section is in the part of the induced hydraulic fracture that is far away from the wellbore (Fig. 6-13).

<table>
<thead>
<tr>
<th>Table 6-4. Simulated Fracture Model</th>
</tr>
</thead>
<tbody>
<tr>
<td><strong>Hydraulic Fracture Geometry</strong></td>
</tr>
<tr>
<td>Max. hydraulic fracture half-length $X_f$ (ft)</td>
</tr>
<tr>
<td>Hydraulic fracture height (ft)</td>
</tr>
<tr>
<td>Hydraulic fracture width (ft)</td>
</tr>
<tr>
<td><strong>Propped Conductivity</strong></td>
</tr>
<tr>
<td>Propped fracture half-length $X_f$ (ft)</td>
</tr>
<tr>
<td>Propped fracture height (in)</td>
</tr>
<tr>
<td>Average propped width (in)</td>
</tr>
<tr>
<td>Effective conductivity (mD.ft)</td>
</tr>
<tr>
<td>Average gel concentration (kg/ft$^3$)</td>
</tr>
<tr>
<td>Effective FCD (Fracture conductivity dimensionless)</td>
</tr>
</tbody>
</table>

<table>
<thead>
<tr>
<th>Table 6-5. Comparison of Fracture Design Parameters</th>
</tr>
</thead>
<tbody>
<tr>
<td>Fracture Design</td>
</tr>
<tr>
<td>-----------------</td>
</tr>
<tr>
<td>$X_f$ (ft)</td>
</tr>
<tr>
<td>Conductivity (md.ft)</td>
</tr>
<tr>
<td>Propped half-length (ft)</td>
</tr>
</tbody>
</table>
Figure 6-13. Fracture width, proppant concentration, and fracture conductivity of the KGD fracture model simulation result.

The simulated well test analysis of the previous model (Table 6-5) without any DFN included is shown in Fig. 6-14. Note the match of the early-time region, which is most affected by the fracture. It is noted that after the fracture response is seen, the increase of permeability is actually due to the flow passing through the unpropped section, which is linear flow because it is flow through an open crack (very high conductivity, with negligible $\Delta p$ in the fracture) that is connected to the DFN.

In unconventional tight reservoirs, the shape and structure of the induced fracture in the complex natural fracture model has a significant effect on the flow from the reservoir rock to
the natural fracture and then through the induced fracture. This is illustrated in the well test response shown in Fig. 6-14, where the simulation of an induced fracture with propped and unpropped sections of the induced hydraulic fracture affects the transient flow from reservoir rock to the hydraulic fracture.

![Log-log plot of well test simulation result of the KGD simulated fracture model incorporated within the production grid without DFN.](image)

**Figure 6-14.** Log-log plot of well test simulation result of the KGD simulated fracture model incorporated within the production grid without DFN.

The preceding stimulation presents an induced hydraulic fracture in a fracture grid that is incorporated in a bigger model. The DFN in the fracture grid is enclosed inside the fracture grid and does not extend into the outer production grid. Thus, it is able to simulate complex hydraulic fracture network propagation in a rock with a complex, predefined natural fracture network.

A change in permeability across the fracture is observed that matches a reflection of the propped and unpropped fracture in the simulated fracture model, as shown in Fig. 6-15.
Figure 6-15. Well test response of the KGD fracture model without the geomechanical effect on the DFN.

6.8.2 Sensitivity of parameters that affect the Young’s Modulus

The parameter that has the greatest effect on the resulting fracture is the formation Young’s modulus. Table 6-6 shows the effect of the formation Young’s modulus on the fracture half-length.

<table>
<thead>
<tr>
<th>Formation Young’s Modulus (GPa)</th>
<th>Fracture Half Length (ft)</th>
</tr>
</thead>
<tbody>
<tr>
<td>0.1</td>
<td>88.6</td>
</tr>
<tr>
<td>5</td>
<td>518.4</td>
</tr>
<tr>
<td>50</td>
<td>961.3</td>
</tr>
</tbody>
</table>

6.8.3 Effect of DFN intensity on the fracture half-length and well test response

When a simple DFN fracture network is applied in the production grid, the effect of the propped section and the non-propped section is clear on the decline of the pressure derivative log-log plot (Fig. 6-16). The early-time region reflects linear flow that matches that of the induced hydraulic fracture.
Figure 6-16. Comparison of the well test response before and after the addition of the DFN.

The purple derivative curve reflects the results of the induced hydraulic fracture without the DFN in the model. The brown curve shows the results of the same model with the same induced hydraulic fracture but with the addition of a simple DFN around the fracture model, which is generated by Mangrove simulation software.

Here it is noted that the decline observed in the well test log-log derivative curve is actually related to a significant improvement of the permeability due to the flow from the propped part of the induced fracture to the unpropped section of the induced fracture.
6.9 Simulation Approach

There are several distinctive features that are observed in the actual well test response that is the subject of this research. First, there is a sinusoidal change (numerical effects due to gridding) in permeability in the middle-time region that represents a change in storativity. This is followed by a significant increase in permeability in the late-time region. There is a wide variation in the pressure response, although the reservoir pressure is slightly less than 3500 psi and the reservoir lithology is a tight, naturally fractured sandstone. Whereas previously it has been demonstrated that the variation of the transient pressure response may be well represented by a radial composite model that is based on a change of permeability in circular zones extending away from the well, subsequently it was demonstrated that the simulation of homogeneous reservoir properties with variations in the natural fracture network around the well may lead to these variations in permeability as well.

It was previously demonstrated and proved that the subject well test response is repeatable and has been observed in multiple locations worldwide in wells that pass through tight, naturally fractured sandstone reservoirs post fracture. This leads us to investigate and determine if the response of the well test is a result of the near-wellbore geomechanical stress changes that are induced in the virgin reservoir as a result of a hydraulically induced proppant-filled fracture.

Secondly, the anomalous behaviour of the transient pressure curve post fracture is interpreted to be a reflection of different permeability regions that exist away from the induced fracture zone.

The intention of this study is to formulate a workflow to specifically investigate two issues:

- The effect of the change of geomechanics on a well test response
- The effect of the change of geomechanics on the DFN post fracture

The three main geomechanical parameters investigated are

- Normal shear
- Strain
- Volumetric total strain

6.10 VISAGE-ECLIPSE Coupling

The concept of two-way coupling is based on linking a reservoir simulator to a mechanical simulator, thus the interaction between stress, pressure, and permeability can be simulated (Fig. 6-17). In two-way coupling, pressure change affects the change in effective stress, resulting in
changes in strain. On the other hand, changes in strain modify permeability or transmissibility, which leads to pressure redistribution (Zhang et al. 2011).

Figure 6-17. Workflow schematic of the two-way coupling process between ECLIPSE and VISAGE modelling.

The basic concept is based on solving the governing equations of fluid flow and geomechanics simultaneously in an iterative, coupled approach. This is achieved by an exchange of information between the fluid flow simulator and the geomechanics simulator.

Initially, a first time step in the workflow is simulated using the ECLIPSE finite-difference simulator; the resulting data (pressure, temperature, and saturation) is fed as input into the VISAGE simulator and a geomechanical simulation is performed. The output of the VISAGE simulator is based on a change of permeability due to the stress calculation, this is then input into the ECLIPSE simulator and an ECLIPSE simulation is performed, thus yielding a new value of pressure, temperature, and saturation. The process is then iterated through all the time steps of the ECLIPSE simulation and the results reflect the actual change of permeability due to changes in stress and geomechanics.
6.11 Application of VISAGE Coupling

The geomechanics reservoir model considers the state of stress and the mechanical behaviour of the reservoir and adjacent formations extending up to the surface. The initial model grid, which is created using the ECLIPSE simulator, is placed into what is called an embedded grid. This consists of the expansion of the normal grid in all four directions. The direction above the model represents the overburden exerted on the formation, and the expansion in the direction below the grid represents the underburden of the model. The two side extensions represent plate segments of the side of the model. The created embedded gridformulates new zones and segments around the reservoir. This results in an embedded model which represents, and will be used to calculate, the geomechanical stress exerted on the model and, consequently, on the reservoir layer.

Material modelling defines the different types of rock and sets up their associated parameters, such as Young’s modulus, Poisson’s ratio, and bulk density. The material properties are divided into two groups—elasticity model and failure criteria. Each elasticity model or failure criteria has a group of associated parameters. The set of parameters that make up a material are uniquely defined by the elasticity model and failure criteria. The elasticity model describes the linear behaviour of the material; the failure criteria describes how the material behaves after it has failed.

The different geomechanical properties are then populated to describe the characteristics of the rock in each cell of the grid. The property value of each grid cell is determined by the value of the related parameter in the previously assigned material. This process defines the five geomechanical parameters—Young’s modulus, Poisson’s ratio, bulk density, Biot’s elastic constant, and linear thermal expansion coefficient. In this way, regions within the embedded grid are associated with specific types of rock and material.

The process of discontinuity modelling formulates the existence of faults and DFNs that are present in the model. The output yields DFN mapping objects and fractures, which are considered as a multi-laminate constitutive model and simulate the fractured or jointed reservoir rock. The multi-laminate theory is used to mimic an equivalent material that represents rock mass. The intact rock and each fracture set are modelled separately as viscoplastic modules. These separate modules are then integrated to formulate an overall viscoplastic system. In essence, the intact rock and the fracture sets follow different constitutive laws and strains, and their properties can be extracted separately (Jin et al. 2000). Pressure and temperature are then defined in a process that runs the geomechanics simulation coupled to the
reservoir simulations. The initial pressure and temperature conditions are first identified and then an iteration of the consequent steps begins.

Through this overall process, the model is set up on the basis of the geomechanical properties, the discontinuity mapping of the DFN, and the pressure data from the simulation. Boundary conditions are set that define the operating conditions that are applied to the model during the simulation and include, minimum horizontal stress ($SH_{\text{min}}$) gradient, $SH_{\text{min}}$ offset, maximum horizontal stress ($SH_{\text{max}}$), $SH_{\text{max}}/SH_{\text{min}}$, and $SH_{\text{max}}$ azimuth. Following this overall setup, simulation initiation then starts and the alternating runs of the VISAGE and ECLIPSE simulations are done simultaneously and consecutively.

### 6.12 The VISAGE Model Setup

Initially, an embedded grid was created that incorporates the complete production grid, which has the fracture grid integrated inside it (Fig. 6-18). The embedded model is created on the basis of the extension of layers of cells above, below, and around the original grid. The layers above represent the overburden stress, the layers below represent the underburden stress, and the cells on the sides represent the sideburden. Table 6-7 lists the dimensions of the embedded grid.

![Embedded model setup with overburden, underburden, and sideburden around the reservoir model.](image-url)
### Table 6-7. Embedded Grid Dimensions

<table>
<thead>
<tr>
<th>Reservoir</th>
<th>Fracture grid properties</th>
</tr>
</thead>
<tbody>
<tr>
<td>Sideburden</td>
<td>5 cells in each direction extended by 1640 ft for each, with geometric factor 2</td>
</tr>
<tr>
<td>Underburden</td>
<td>2 cells extended by 3281 ft, with geometric factor 1.5</td>
</tr>
<tr>
<td>Overburden</td>
<td>10 cells extended by small factor and geometric factor 1.5</td>
</tr>
</tbody>
</table>

The following workflow was used to set up the geomechanical model:

1. Perform material modelling to assign the reservoir type, which in this study is sandstone.

2. Assign geomechanics functions to regions that are previously set. The main parameters used in the geomechanics functions are
   - Volumetric total strain vs. initial permeability multiplier
   - Normal plastic strain vs. shear permeability multiplier
   - Shear plastic strain vs. Normal and shear permeability multiplier.

3. Populate the model with the reservoir properties (e.g., stress, strain, Young’s modulus, and region location from fracture) and define function for each region.

4. Using the coupling stage between ECLIPSE simulation and VISAGE calculations, define pressure and temperature and run VISAGE simulator time steps.

5. Define specific boundary conditions and apply the geomechanical reservoir simulation.

#### 6.13 Effect of Geomechanics on the Well Test

To investigate the effect of geomechanics on well test interpretation, initially the use of the field case (prior to hydraulic fracturing) with the same geomechanical properties of the actual reservoir layer is employed. This will be the base case scenario and will be used to compare the results before and after the application of two-way coupling using the VISAGE simulator.

Next, different stress regions are applied in and around the well to evaluate the effect of those conditions on the well test response. These regions will be applied across a uniform DFN that is distributed uniformly around the well.

Different permeability functions will then be applied to the different regions (Figs. 6-19 and 6-20), and the difference between each well test will be compared in the respective early-, middle- and late-time regions of the well test.
Figure 6-19. Embedded model designed with regions or zones around the fracture.

Figure 6-20 Regions designed around the induced hydraulic fracture.
The result of the well test simulation of the preceding model in its initial stage without geomechanical permeability updating functions is shown in Fig. 6-21.

![Simulated well test response without the application of geomechanical permeability updating functions](image)

**Figure 6-21. Simulated well test response without the application of geomechanical permeability updating functions.**

### 6.13.1 The early-time region

There is typically no effect of geomechanics on the well test response in the early-time region. The early-time response typically reflects the transient pressure in the wellbore and the immediate near-wellbore area. In tight sandstone formations that are simulated with an induced hydraulic fracture, this region will typically show bilinear flow due to the flow from the high-permeability fracture to the wellbore and flow from the reservoir to recharge the fracture.

### 6.13.2 The middle-time region

Figure 6-22 shows the simulated well test response when geomechanical permeability updating functions (Fig. 6-23) are implemented in regions 2 and 3 (Fig. 6-19) of the preceding model. The response in the middle-time region is affected.
When the geomechanical permeability updating functions are applied in regions 3 and 4 (Fig. 6–19), it is noted that well test results show that the middle-time region is the region most affected by the geomechanics effects; this region is located 262.5 to 656 ft from the hydraulic fracture. The response from the simulated well test that uses the same parameters as used in the previous function and implements changes in the shear plastic strain only is shown in Fig. 6-23.
Figure 6-23. Log-log well test response when applying different geomechanical permeability updating functions with changes in shear plastic strain in regions 2 and 3 around the fracture.

Table 6-9. Geomechanical Permeability Updating Functions (Scenarios R1 and G2)

<table>
<thead>
<tr>
<th>Volumetric Total Strain (Mpa)</th>
<th>Initial Permeability Multiplier</th>
<th>Normal Plastic Strain (Mpa)</th>
<th>Shear Permeability Multiplier</th>
<th>Shear Plastic Strain (Mpa)</th>
<th>Shear Permeability Multiplier</th>
</tr>
</thead>
<tbody>
<tr>
<td><strong>R1 Function</strong></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>−2.36E−06</td>
<td>0.001</td>
<td>−1.90E−07</td>
<td>0.001</td>
<td>−1.90E−07</td>
<td>0.001</td>
</tr>
<tr>
<td>0</td>
<td>1</td>
<td>0</td>
<td>1</td>
<td>0</td>
<td>1</td>
</tr>
<tr>
<td>3.97E−05</td>
<td>0.001</td>
<td>5.00E−07</td>
<td>0.001</td>
<td>2.20E−06</td>
<td>0.001</td>
</tr>
<tr>
<td><strong>G2 Function</strong></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>−5.24E−03</td>
<td>0.01</td>
<td>−1.90E−02</td>
<td>0.01</td>
<td>−5.19E−03</td>
<td>0.01</td>
</tr>
<tr>
<td>0</td>
<td>1</td>
<td>0</td>
<td>1</td>
<td>0</td>
<td>1</td>
</tr>
<tr>
<td>2.40E−03</td>
<td>100</td>
<td>5.00E−02</td>
<td>100</td>
<td>2.20E−02</td>
<td>100</td>
</tr>
</tbody>
</table>

It is noted that a large change in permeability is related to the effect (observed in the middle-time region) of the geomechanical properties that relate to changes in the shear plastic strain from −1.90E−07 to −5.19E−03 Mpa.
### 6.13.3 The late-time region

When geomechanical permeability updating functions are implemented in the outermost regions, namely regions 5 and 6, the late-time region of the derivative curve shows only a small effect due to geomechanics; the change in stress and strain is very small (Fig. 6-24).

![Graph showing log-log response after implementing different geomechanical permeability updating functions in regions 5 and 6 around the fracture.](image)

**Figure 6-24.** Log-log response after implementing different geomechanical permeability updating functions in regions 5 and 6 around the fracture.

Here it is concluded that despite the range of change of functions for the permeability multiplier is between 100,000 and 0.000001, the equivalent range of volumetric total strain is between −0.00000019 Mpa and 2.20E−06 Mpa. For the black curve in Fig. 6-24, the increase of permeability reflects a 25% change of permeability (from 20 mD to 25 mD). For the purple curve, the change is implemented in the shear permeability multipliers and reflects a change of even less than 25%.
Table 6-10. Geomechanical Permeability Updating Functions (Scenarios X1, G2, X2)

<table>
<thead>
<tr>
<th>Volumetric Total Strain (Mpa)</th>
<th>Initial Permeability Multiplier</th>
<th>Normal Plastic Strain (Mpa)</th>
<th>Shear Permeability Multiplier</th>
<th>Shear Plastic Strain (Mpa)</th>
<th>Shear Permeability Multiplier</th>
</tr>
</thead>
<tbody>
<tr>
<td>X1 Function</td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>–2.36E–06</td>
<td>100000</td>
<td>–1.90E–07</td>
<td>100000</td>
<td>–1.90E–07</td>
<td>100000</td>
</tr>
<tr>
<td>0</td>
<td>1</td>
<td>0</td>
<td>1</td>
<td>0</td>
<td>1</td>
</tr>
<tr>
<td>3.97E–05</td>
<td>1.00E–09</td>
<td>5.00E–07</td>
<td>1.00E–09</td>
<td>2.20E–06</td>
<td>1.00E–09</td>
</tr>
<tr>
<td>G2 Function</td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>–5.24E–03</td>
<td>0.01</td>
<td>–1.90E–02</td>
<td>0.01</td>
<td>–5.19E–03</td>
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<tr>
<td>0</td>
<td>1</td>
<td>0</td>
<td>1</td>
<td>0</td>
<td>1</td>
</tr>
<tr>
<td>2.40E–03</td>
<td>100</td>
<td>5.00E–02</td>
<td>100</td>
<td>2.20E–02</td>
<td>100</td>
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<td>X2 Function</td>
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<tr>
<td>–2.36E–06</td>
<td>0.000001</td>
<td>–1.90E–07</td>
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<td>1</td>
<td>0</td>
<td>1</td>
</tr>
<tr>
<td>3.97E–05</td>
<td>100000</td>
<td>5.00E–07</td>
<td>100000</td>
<td>2.20E–06</td>
<td>100000</td>
</tr>
</tbody>
</table>

6.14 The Application of Visage Coupling on Subject Case

To test Hypothesis C, a geomechanical function was implemented and was based on the DFN previously implanted in the previous simulations (i.e., DFN with equal distribution), excluding Zone 1, which contains the induced hydraulic fracture and will not have an effect on the well test results because it corresponds to the early-time region. The geomechanical permeability updating functions were implemented in the original model to measure the geomechanical effect at the region that corresponds to the single multiple of the half-length (same half-length from either side) of the induced hydraulic fracture (Figs. 6-25 and Table 6-11).
Figure 6-25. Comparison of the actual well test response with the simulated well test response with four different geomechanical permeability updating functions, showing a close match to the actual case.

Table 6-11. Geomechanical Permeability Updating Functions (Scenarios I1, I2) Implemented in the Simulated Well Test Results Plotted in Fig. 6-25

<table>
<thead>
<tr>
<th>Function</th>
<th>Volumetric Total Strain (Mpa)</th>
<th>Initial Permeability Multiplier</th>
<th>Normal Plastic Strain (Mpa)</th>
<th>Shear Permeability Multiplier</th>
<th>Shear Plastic Strain (Mpa)</th>
<th>Shear Permeability Multiplier</th>
</tr>
</thead>
<tbody>
<tr>
<td>I1</td>
<td>10^{-2.36E-06}</td>
<td>100000</td>
<td>-1.90E-02</td>
<td>100000</td>
<td>-1.90E-07</td>
<td>100000</td>
</tr>
<tr>
<td></td>
<td>0</td>
<td>1</td>
<td>0</td>
<td>1</td>
<td>0</td>
<td>1</td>
</tr>
<tr>
<td></td>
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<tr>
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<td>2.20E-06</td>
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</tr>
</tbody>
</table>
In the review of the four cases (Fig. 6-25), it is seen that the oscillation of simulated data around the actual data is actually achieved when the region that corresponds to the region that is located 80 m away from the fracture has geomechanical permeability functions applied to it.

It is concluded that the effect of the induced fracture on the zones around the induced hydraulic fracture (Fig. 6-26) is summarised as follows and illustrated in Fig. 6-26:

- In Zone 1, the flow is linear due to the flow through the induced hydraulic fracture; there is negligible change in pressure across the fracture, as the high $k_f$ results in linear flow behaviour that is typical in tight formations.

- Zone 2 permeability ($k_1$, Fig. 1-2) exhibits an increase that corresponds to the flow coming from the perpendicular fractures that intersect the induced hydraulic fracture. These fractures are probably not fully filled with proppant, and thus are basically open fractures that accelerate flow to the induced hydraulic fracture and provide a permeable conduit for flow.

- Zone 3 permeability ($k_2$, Fig. 1-2) is decreased because the elongated perpendicular-oriented fractures are intersected by the parallel fractures that have been affected by the total normal stress and exhibit reduced permeability. Thus, the average permeability of both fractures is less than the permeability of the perpendicular fractures.

- Zone 4 permeability ($k_3$, Fig. 1-2) exhibits an increase that corresponds to flow from both the perpendicular and the parallel fractures. The perpendicular fractures have been elongated and enhance flow as they intersect with the parallel fractures that have not been affected by strain and thus have high permeability as well, even though they have not been elongated. The flow now follows a pervasive flow mechanism with contribution from all the components intersecting and flowing with each other; i.e., the induced hydraulic fracture, the DFN with all its components, and the matrix.
6.15 Results
A finite-element simulation was implemented on a model that reflects the pre-simulated well test results of a naturally fractured reservoir.

- The match of the early fracture flow that was observed on the post-stimulation results of the well test were attempted to be matched using different fracture models in order to investigate which would be more applicable. The simulation results confirm that the shape and model of the KGD fracture is the most appropriate model design. Simulation results matched the actual well test results and the actual pumped schedule that was injected.

- A simple DFN network was added to the model that included the induced hydraulic fracture, and simulations were performed prior to the addition of any geomechanical functions.

- When geomechanical functions were implemented on different regions around the well and the induced fracture, it was concluded that the best match of the actual well test results were obtained in and around a region that is equal to the half-length of the induced hydraulic fracture.
6.16 Discussion

In essence, it is concluded that the region surrounding the induced hydraulic fracture in tight sandstone formations that will be affected by geomechanical effects is typically located a distance from the wellbore that is a multiple of the fracture half-length (same length after the fracture half-length zone).

The fracture shape and proppant distribution in the induced hydraulic fracture affects the well test derivative as well as the interaction of the induced hydraulic fracture with the DFN.

The results of the coupled reservoir-geomechanical simulations indicate that perturbation of the reservoir mechanical equilibrium specifically leads to progressive strain localization in a region around the induced fracture. The normal strains resulting from geomechanical computations are interpreted in terms of permeability variations, using a fracture and a DFN permeability model to improve the dynamic description of fluid flow and history matching.
Chapter 7
Conclusions

The objective of this thesis was to observe the behaviour of well tests in unconventional tight sandstone reservoirs and to analyse the sample field well test data collected, with the goal of obtaining fracture parameters and an understanding of the reservoir behaviour near the induced hydraulic fracture in tight sandstone reservoirs.

This thesis is divided into three parts. The first part identifies and describes a unique well test signature that is obtained from tight dry gas sandstone formations and which has been recurrently found in such reservoirs after stimulation by hydraulic fracturing. This has been confirmed by screening well test transient pressure analysis of log-log plot signatures from different locations worldwide. It was thus noted that this unique well test signature is probably not geology related at field scale, but instead is a specific signature related to the near-wellbore region around the induced hydraulic fracture.

The second part examines the well test analysis of this signature analytically and numerically. Analytical well test software was used to analyse and model the signature as a typical radial composite reservoir response. Numerically, the same signature was achieved by modelling a well in the middle of multiple permeability regions. However, as this did not explain the fact that the well test signature was found repeatedly in multiple locations, the cause for this unique signature was further explored. Thus a series of hypotheses were proposed related to the DFN that is around the wellbore. Each hypothesized scenario was modelled separately using finite-element simulations to confirm which hypothesis may be more adequate to explain this behaviour. Sensitivity studies were performed to investigate what are the factors that impact the natural fracture network and may produce different permeability responses in different regions around the well. The result of this study confirms that differences of aperture or permeability of natural fractures may exist at different regions or distances from the well.

The third part investigates the effect the induced fracture may have on tight sandstone formations. This investigation included the simulation of different fracture models that may exist and the subsequent analysis of the fracture model that best matched the field data. Included was the investigation of the geomechanical effect around the induced fracture and its effect on the well test response.
7.1 Tight Sandstone Formation Well Test

A systematic and practical approach for analysing well test data of tight sandstone dry gas formations was developed that successfully models the near-wellbore effects post hydraulic fracture stimulation. First, 2D well test analytical models were used to investigate the derivative curve shapes that resulted from an actual field case; then deconvolution was applied to confirm the boundary of the well test data. 3D numerical models were then used to model and match the well test and deconvolution results that were obtained. All simulations used measured PVT properties and core data from the actual field dataset as input parameters. The analysis of the actual well test and comparison with the simulation results of the same test conducted on the simulation models confirmed that they resulted in the same derivative response. This analytical and numerical study has enabled the identification of the distance of the boundaries that compose the radial composite response in the well test analysis.

The application of a DFN in the finite-element grid was used to simulate the reservoir model, with the changes in the composite regions modelled as DFN anisotropy, as compared to the typical changes in grid properties, to obtain a radial composite model response. Thus it has been proved that the radial composite response is actually related to changes in the DFN that surrounds the well and the induced fracture. The investigation included simulation tests to evaluate the effect of the geomechanics on well test data and analysis (Fig. 7-1). The same technique was applied to the actual field data to investigate the radius of the region that is affected by the induced fracture and the main geomechanical properties that affect the DFN around the induced fracture.
Figure 7-1. Suggested workflow for well test analysis of tight sandstone naturally fractured formations.

The suggested workflow offers the opportunity to use well test results from tight sandstone reservoirs to design optimal (right-sized) hydraulic fracture stimulations that can connect with a pre-existing DFN when taking into consideration the scale-dependent rock framework properties.

This thesis presents the first comprehensive study of this unique well test signature and subject. This study provides the following conclusions:

1. Tight sandstone reservoirs stimulated with induced hydraulic fracturing may often display a unique well test signature.

2. The data-mining process confirmed that this characteristic well test signature exists in several tight sandstone reservoirs post-fracturing and is associated with well test analysis results that show composite behaviour with multiple permeability regions around the wellbore. The well test response is similar to the composite behaviour seen in lean gas condensate wells, where there it is due to the existence of a condensate bank that is formed during the well test as the pressure drops below the dewpoint, thus causing different permeability regions around the wellbore. Since this well test
signature was reported from multiple locations in several locations worldwide with similar reservoir conditions (i.e., tight sandstone, stimulated by induced hydraulic fracture, dry gas), the recurrent signature is likely to be related to the effect of the induced fracture.

3. After investigation, factors that may cause the unique well test signature to be similar to that of a lean gas condensate reservoir (e.g., PVT, core data, geological setting, well production, and wellbore-related issues) are considered inapplicable to the subject case.

4. The typical linear and bilinear flow response that is seen in the early-time region of the subject well test is due to the existence of a high-permeability streak intersecting the wellbore (i.e., induced hydraulic fracture). This was modelled and simulated as per the actual fluid mixture of proppant and gel to confirm the shape, half-length and width of the fracture. The proppant distribution in the fracture is of vital importance because it does affect the well test response. The manner in which the proppant is distributed within the fracture crack affects the interaction of the induced hydraulic fracture with the natural fracture network around it. The initial linear flow is a reflection of a high to moderate $C_{fd}$ (dimensionless fracture conductivity) and causes pseudolinear flow due to negligible $\Delta p$ in the fracture plane. It was found that because the far part of the induced hydraulic fracture may have low concentration of proppant, the flow from the natural fracture network is enhanced, as it is reflecting flow from the narrow natural fractures into a wider region of open flow.

5. The characteristic derivative curves that identify multiple mobility zones that are noted after the bilinear and linear flow in the well test imply a change in storativity or a region of changed mobility, which confirms that the flow passes through different regions of natural fractures. If the natural fracture network was homogeneous and intact, then the well test response would be expected to match the initial well test derivative curve prior to the stimulation. However, the existence of the change of the storativity or mobility region implies that there is a change that has affected the natural fracture network in the region around the induced hydraulic fracture.

6. Well test analysis using typical analytical well test software and deconvolution confirmed the boundary conditions of the reservoir. Significant results were obtained initially from deconvolution, confirming the dual-porosity response, which is typical for formations with natural fractures. However, these software programs are not able to
model the natural fracture networks. Thus inadequate reservoir characterisation can be misleading when attempting to model naturally fractured formations using the typical analytical models. 3D numerical modelling allows the DFN network to be incorporated in the reservoir model.

7. The dimensions and properties of the induced hydraulic fracture are obtainable by proper modelling of the fracture shape as a 3D fracture geometry that intersects a DFN network. The proppant distribution within the fracture shape affects the fracture conductivity, and interaction with the DFN around the hydraulic fracture is affected by the same parameters.

8. Modelling of tight sandstone naturally fractured reservoirs should be performed with the use of a DFN model and finite-element simulation. The specific modelling of the DFN is sensitive to the properties of the fracture network in terms of the aperture, orientation, and shape factor (sigma). It has been proved that these factors affect the well test response significantly when compared to the previous traditional modelling techniques, utilising the dual-porosity method in which the sigma factor is the only parameter that communicates the interaction between the matrix and the fracture network.

9. The effect of geomechanics on the well test interpretation is significant because the flow in tight sandstone formations is directly correlated to the flow coming from the natural fracture network. The matrix is typically very tight, and the flow is a result of an efficiently connected fracture network, enabling passive flow to take place throughout the network and then connect to the wellbore through the induced fracture. The normal strain is the actual parameter that contributes to the connection and enhanced flow from the DFN, resulting in a well test result that matches the actual well test obtained from actual field data.

10. This study demonstrates that geomechanic effects impact the region around the induced hydraulic fracture. From 3D finite-element simulations utilising the two-way coupling technique with a geomechanical simulator, this impacted region was shown to occur at a distance equal to the half-length of the fracture in the same fracture orientation direction.
7.3 Comparison of Different Remedial Solutions to Better Simulate Tight Sandstone Formations

The following are the main points derived from this section:

1. Primarily the core of the study and conclusions are based on the reaction of the DFN to the induced hydraulic fracture and are based on the fracture parameters.

2. Prior to the design and execution of induced hydraulic fracture simulations, comprehensive information needs to be considered in order to address the potential geomechanical effect.

3. The simulations have demonstrated that the orientation and size of the natural fractures affect the increase or decrease in permeability. These factors are already fixed by the geological and geomechanical setting and composition. The geomechanical effect that exists at the half-length of the induced fracture is unavoidable because the fracture will typically propagate in the direction of the principal horizontal stress and open against the minimum horizontal stress. The fracture principal plane is oriented in the direction $\sigma_{h\text{max}}$ and opens against $\sigma_{h\text{min}}$.

4. Coupling the two factors may enhance the productivity of tight sandstone reservoirs as it would provide a better understanding of how the induced fracture has propagated and its interaction with the natural fracture network. Typically there are many variables that control fracture propagation, very few of which we can control, mainly the $\mu_f$ (viscosity) of frac fluids, injection rates, field of stress, formation properties (Young’s modulus and Poisson’s ratio), pressure distribution, etc. The only ones we have any real control over are $\mu_f$ (frac fluid viscosity) and $q$ (injection rate). However the later will not really affect to any degree the branching of the induced hydraulic fracture or its intersection in the natural fractured network. This will employ the use of very high injection power to be able to inject the induced fracture and intersect the natural fracture network.

5. The initiation of the induced fracture in the direction of the maximum horizontal stress requires oriented perforation techniques and the ability to stage the fracture in multiple stages. The primary stage is the use of tortuosity to orient the initial fracture in the direction of the maximum horizontal stress, followed by an increased injection pressure to extend the initial crack toward the maximum horizontal stress direction.
7.4 Recommendations

1. The analysis of tight sand well test results should not follow the typical practices currently used. The integration of geology and the use of analytical well test models are useful tools to identify near-wellbore effects and reservoir boundaries; however, no analytical model has been published for composite behaviour that is the result of geomechanical effects. The same applies for hydraulically fractured analytical well models; the modelling is based on the linear response of the fracture and does not model the region beyond the fracture or account for the interaction of the fracture with the virgin reservoir beyond. Further research work is necessary to develop an analytical model applicable for tight sand well test analysis.

2. It is essential to understand and take into consideration the natural fracture network that is around the well prior to designing induced fracture simulation. The design and application of the induced fracture orientation should take into consideration the shape factor and orientation of the natural fracture network.

3. The induced hydraulic fracture shape and the proppant distribution inside the fracture and the effective fracture conductivity are the basis of interaction with the DFN.

4. Integration of the modelling of the induced hydraulic fracture and the DFN should be systematically used to guide the design and interpretations of well tests in tight sandstone reservoirs as was done in this study.

5. The workflow used in the interpretation of the actual well test used in this study has proved valid in tight sandstone reservoirs.

6. The simulation workflow that computes effective simulation of an induced hydraulic fracture in tight sandstone formations followed by two-way coupling of finite-difference and finite-element geomechanical simulations was tested and found to be the optimal way to model an induced hydraulic fracture and the DFN in tight sandstone formations.
Thus it may not be the nature of the fluid that is causing these anomalies (waviness) on the pressure derivative, but the nature of the rock and its rippled properties away from the fracture; so geomechanical and rock properties can cause a derivative response that resembles one from a lean gas condensate reservoir. Analysis of such tests should first be done knowing what the nature of the produced fluid is and then with focus on interpreting the derivative with understanding the heterogeneity of rock mechanical properties, as was demonstrated.

The research has been conducted using the latest modelling techniques with the motive to explain the repetitive anomaly in real field data. The results help to optimize the most effective completion methods (fracturing design), and help unlock this valuable resource, for which global appetite for tight gas does not cease to grow.
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Nomenclature

BH  Bahar el Hammar
BU  buildup
C   wellbore storage coefficient
d1  distance to first boundary
d2  distance to second boundary
d3  distance to third boundary
D   non-Darcy flow coefficient
DFIT diagnostic fracture injection test
DFN discrete fracture network
DST drillstem test
ETR early-time region
FBHP flowing bottomhole pressure
FEFV finite element-finite volume
FEM finite-element model
FMI fullbore formation microimager
GF  Garet el Guefoul
GRI Gas Research Institute
h   thickness
IFDM integrated finite-difference model
IMPES implicit pressure explicit saturation
IPR inflow performance relationship
k   permeability
kf  fracture permeability
km  matrix permeability
krg gas relative permeability
krog oil relative permeability in presence of gas
krw water relative permeability
kxy directional (horizontal) permeability
k(z) directional (vertical) permeability
KGD Kristianovic–Geertsma–de Klerk (model)
(k/μ)t total mobility
(kh/μ)t total mobility thickness
(kxy/μ)t total horizontal mobility
(kz/μ)t total vertical mobility
L   distance between upper and lower boundaries
LTR late-time region
m(p) real gas pseudopressure
MD measured depth
MDRT measured depth from rotary table
MDT modular formation dynamics tester
MLF-P3D multilayer fracture pseudo 3D (model)
MMSCF million standard cubic feet
MSCF  thousand standard cubic feet
MSTB  thousand standard barrels
MTR  middle-time region
(pav)f  final average reservoir pressure
(pav)i  initial average reservoir pressure
pbh  bottomhole pressure
pdew  dewpoint pressure
pi  initial pressure
pwf  flowing pressure at start of flow period
PDE  partial differential equation
PDG  production downhole gauge
PKN  Perkins–Kern–Nordgren (model)
PLT  production log test
PVT  pressure-volume-temperature
q  flow rate
Q  flow rate
Qg  gas flow rate
Qo  oil flow rate
Qw  water flow rate
QH  Quartzites de Hamra
RFT  repeat formation tester
s(c)  completion skin factor
s(t)  total skin factor
s(w)  wellbore skin factor
SCF  standard cubic feet
SFE  Stage Field Experiment
SMTI  seismic moment tensor inversion
STB  standard barrel
Sw  water saturation
t  time
tp  duration of flow period
TLSD  total least squares deconvolution (software)
TSS  tendency for shear stimulation
UFM  unconventional fracture model
WT  well test
xf  fracture half-length

βg  gas formation volume factor
Δp  change in pressure
Δt  elapsed time
λ  regularisation parameter
μ  viscosity
μg  gas viscosity
ν  relative weight for rates
νg  gas velocity
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<th>Symbol</th>
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<tr>
<td>$\sigma_{imin}$</td>
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<td>$\sigma_1$</td>
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Appendix A

A.1 Production Log Test Results

Table A-1. Well 2 Production Contribution per Reservoir Layer

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<th>Production Interval</th>
<th>Target</th>
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<th>PLT @ 40” Choke</th>
<th>Reservoir</th>
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<td></td>
<td></td>
<td>Depth</td>
<td>Surface Rate 175,000 m³/d</td>
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<td>4%</td>
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Table A-2. Downhole Flow Rates from Test 2 Production Log in Well 2 at 40/64-in Choke Size witha Surface Rate of 257,000 m³/d

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<th>Formation</th>
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<th>Qg (scf/d)</th>
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### A.2 Petrophysics and Core Analysis Results

Table A-3. Well 2 Core Analysis Results

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<th>PERMEABILITE</th>
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<th>Rd</th>
<th>Vp</th>
<th>Vd</th>
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**REMARQUES:**

Table A-4. Well 2 Measured Core Porosity and Permeability

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<th>Rd</th>
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**REMARQUES:**

Tight Layer in between layer 2 & 3, also confirmed with petrophysical logs.
Figure A-1. Petrophysical analysis of the layers of interest.
A.3 PVT Analysis Results

Table A-5. Well 2 Sample Composition

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<th>Component</th>
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Table A-6. Well 2 Single-Stage Flash Data

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<td>C20+ Mole %</td>
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<tr>
<td>C20+ Mass %</td>
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<tr>
<td>C30+ Mass %</td>
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<td>C7+ MW (g/mol)</td>
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<td>C12+ MW (g/mol)</td>
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<td>C20+ MW (g/mol)</td>
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<td>C30+ MW (g/mol)</td>
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A.4 Pressure Match Tests

Figure A-2. Pressure match of Test 1 and 2 combined
Figure A-3. Test 5 pressure match.

Figure A-4. Test 6 pressure match.
A.5 MDT Correlation

Table A-7. GF-6 MDT Data Points

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A.6 Horner Plot (Test -5)

![Horner Analysis - Flow Period 7](image)

(pav) = 3136 psia

Figure A-6. Extrapolation of Pi (initial pressure) from Horner plot.
Appendix B

B.1 Test 1

Log-Log Match - Flow Period 473

Horner Match - Flow Period 473

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<th>Results</th>
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<td>Radial Composite</td>
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<tr>
<td>Infinite Lateral Extent</td>
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Superposition Function (Mscf/D)
B.2 Test 2

Log-Log Match - Flow Period 7

Horner Match - Flow Period 7

Model
Wellbore Storage and Skin (C and S)
Radial Composite
Infinite Lateral Extent

Results
\( \text{p}_0 \) 3138.888 psia
\( \text{p}_w \) 2357.82 psia
\( k_h(2) \) 1005.1 mD ft
\( k_2 \) 5.411 mD
\( C \) 0.01188 bbl/psi
\( S(w) \) 0.07
\( S_t \) 61.93
\( r_1 \) 16 ft
\( (p_c h)^{1/2} \) 3.425 ft
\( (k_h u)^{1/2} \) 0.006422
\( h_i \) 1854 ft
\( D(p_S) \) 13.05 psi

Superposition Function (Mscf/D)
B.3 Test 3

Log-Log Match - Flow Period 557

Homer Match - Flow Period 557

Model
Uniform Flux Vertical Fracture with C and S
Homogeneous
Single Boundary

Results
\( p_{avg} \) 3140.000 psi
\( pwf \) 964.532 psi
\( k_h \) 29.28 mD ft
\( k \) 0.2928 mD
\( C_1 \) 0.05812 bbl/psi
\( C_2 \) 0.3901 bbl/psi
\( \alpha \) 0.3883 hrs
\( Dp(C) \) 0.971 psi
\( x_f \) 3923.1 ft
\( S(w) \) 7.61
\( S(t) \) -0.70
\( d_1 \) 1.80662 ft
Type d1 No Flow
\( D_{inv} \) 853 ft
\( Dp(S) \) 1972.3 psi
B.4 Test 4

Simulation (Constant Skin) - Flow Period 1207

Log-Log Match - Flow Period 1207
B.5 Test 5

Log-Log Match - Flow Period 7

Horner Match - Flow Period 7

Model
Wellbore Storage and Skin (C and S)
Radial Composite, Three Zones
Single Partially Communicating Boundary

Results
(psv) 3100.000 psia
pwf 2837.310 psia
kh 295.3 mD.ft
k2 9.000 mD
C 0.02058 bbl/psi
S(w) -9.37
S(t) -5.33
r1 7184 ft
(pch)1/2 0.03752
(kh)u1/2 0.1825
l2 24298 ft
(pch)2/3 0.08160
(kh)u2/3 0.6897
xf 0 ft
d1 2500 ft
Kw 0.03240 mD/ft
Hf 500.0 ft
Dinw 2039.1 ft
Dp(S) -4654.0 psi
B.6 Test 6

Log-Log Match - Flow Period 6

Horner Match - Flow Period 6

Model
Wellbore Storage and Skin (C and S)
Radial Composite, Three Zones
Rectangle

Results

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<td>psia</td>
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<td>(pav)</td>
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<td>psia</td>
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<td>mD ft</td>
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<tr>
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<td>mD</td>
<td>0.02070</td>
<td>bbl/psi</td>
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<tr>
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<td>-3.07</td>
<td>ft</td>
<td>42.32</td>
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<tr>
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<td>ft</td>
<td>16.98</td>
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<tr>
<td>(pch)/2</td>
<td>0.02129</td>
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<td></td>
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<tr>
<td>(kh/u)/2</td>
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</table>

Superposition Function (Mscf/D)
Simulation (Constant Skin) - Flow Period 6

Pressure (psia)

Elapsed time (hrs)