A Comprehensive Integrated Approach to Evaluation of Hydraulic Fracturing

PhD Thesis

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To Aigin

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Abstract

Hydraulic fracturing has been known as a pioneering technique of boosting oil production from wells. Although its was primarily invented as a well treatment method, hydraulic fracturing, in recent decades, has become an essential step and integral part of the production from tight formations. Combined with horizontal drilling, hydraulic fracturing has served as the cornerstone of the field development in unconventional resources which could not otherwise be produced commercially.

Growing application of hydraulic fracturing has required and encouraged tremendous research and development of the technique, resulting in extensive innovations in terms of equipment, materials, modeling of the process, and prediction of the outcomes. This, in turn, has increased the number of disciplines involved and the level of complexities of the process and its modeling, particularly in heterogeneous rock formations.

This research is conducted in an attempt to elucidate the need to a holistic approach that integrates the data and analyses from different disciplines, and to propose one such comprehensive analysis workflow for evaluation of the hydraulic fracturing in heterogeneous reservoirs and prediction of its performance and degree of success. A novel method for quantification of heterogeneity impact is proposed through defining a new parameter called heterogeneity impact factor (HIF). Further extending the application of HIF, a predictive technique (DCH) for well performance evaluation is formulated to forecast production from hydraulically fractured wells in heterogeneous reservoirs in a time and cost-efficient manner. To provide a complete picture of the fracking process and its outcomes, the proposed HIF and DCH analyses are supplemented by an innovative economic evaluation component called the analysis of the risk of commercial failure (RCF).

List of Publications

1. H. Parvizi, S. Rezaei-Gomari, F. Nabhani, Z. Dastkhan and W. C. Feng, "***A Practical Workflow for Offshore Hydraulic Fracturing Modelling: Focusing on Southern North Sea***," in *EUROPEC 2015*, Madrid, Spain, 2015a.

2. H. Parvizi, S. Rezaei-Gomari, F. Nabhani, A. Turner and W. C. Feng, "***Hydraulic Fracturing Performance Evaluation in Tight Sand Gas Reservoirs with High Perm Streaks and Natural Fractures***," in *EUROPEC 2015*, Madrid, Spain, 2015b.

3. H. Parvizi, "***Maximising Gas Extraction from Unconventional Resources by Optimising Hydraulic Fracturing***," presentation in the UK Parliament, March 2015.

4. H. Parvizi, S. Rezaei-Gomari, F. Nabhani and A. Turner, "***Evaluation of heterogeneity impact on hydraulic fracturing performance***," *Journal of Petroleum Science and Engineering*, vol. 154, pp. 344-353, 2017a.

5. H. Parvizi, S. Rezaei-Gomari and F. Nabhani, "***Robust and Flexible Hydrocarbon Production Forecasting Considering the Heterogeneity Impact for Hydraulically Fractured Wells***," *Energy Fuels*, vol. 31, no. 8, p. 8481–8488, 2017b.

6. H. Parvizi, A. Dehghan-Monfared, S. Rezaei-Gomari and F. Nabhani, "***Modeling the Risk of Commercial Failure for Hydraulic Fracturing Projects Due to Reservoir Heterogeneity***," *Energies*, vol. 11, no. 218, 2018.

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Chapter 1. Introduction

1.1. Overview

Conventional hydrocarbon resources are no longer able to maintain the production levels corresponding to the global energy demand. As a result, producing oil and gas from increasingly more difficult reservoirs has become an unavoidable challenge for the petroleum industry [1]. High price of energy encourages investments in oil and gas research and developments leading to new and/or improved technologies for recovering more hydrocarbons from the existing resources. Successful implementations of such cutting-edge innovative technologies, on the other hand, lead the oil industry to re-evaluate the assets considering the incremental recoveries made possible through improved production techniques. Hydraulic fracturing, applied to tight and ultra-tight reservoir rocks to enhance permeability, is one such technology that has recently been improved significantly in terms of design and implementation [2]. At the same time, however, these improvements have made the hydraulic fracturing an overwhelmingly complicated method due to the largely heterogeneous nature of most reservoir rocks for which this treatment is considered as well as the level of detailed analyses required from various disciplines prior to performing the hydraulic fracturing jobs. Rock heterogeneity is usually far beyond the level of complexity considered in hydraulic fracture modeling approaches, resulting in reduced certainty and reliability of the modeling schemes. This, in turn, diminishes the certainty of production forecasting methods. To increase the reliability of hydraulic fracture modeling, more inputs and details are required to shift the outcomes of the models closer to what occurs in field implementations. It is therefore required to establish efficient links between the different disciplines, and even different companies and organizations, involved in providing the relevant data and analyses. Thus, it is essential to develop an integrated workflow to accomplish the hydraulic fracturing design and evaluation.

1.2. Hydraulic Fracturing Challenges: Scope of this Thesis

Since its introduction in the late 1940s, hydraulic fracturing has been widely used in North America to achieve higher recovery from low permeability reservoirs and/or to bypass the formation damage around the wellbore [3, 4]. In addition, successful applications of this technique have been reported in other locations including North Sea [5], South America [6], Asia [7] and Middle East [8, 9]. In Southern North Sea (SNS), the practice of hydraulic fracturing dates to 1990s in the Leman [10], Ravenspurn North [11], and Viking [12, 13] fields. However, due to the heterogeneities of SNS reservoir rocks, performing hydraulic fracturing in the SNS reservoirs is much more challenging than North American fields. The SNS reservoir rocks are characterized by the presence of two major elements of heterogeneity: more permeable layers and natural fractures [1, 2]. These distinctions make the fracking designs more complicated and signify the importance of taking an integrated approach to get the most out of the available data [14].

Generally, many steps of analysis are performed prior to any hydraulic fracturing job to ensure its effectiveness. But, in comparison, implementation of hydraulic fracturing in heterogeneous reservoirs requires much more pre-analysis for an optimum design and operation. This is mainly due to the fact that in heterogeneous reservoirs, rock properties vary dramatically and can severely affect the hydraulic fracture performance. To overcome the technical and operational challenges associated with hydraulic fracturing in such reservoirs, multi-disciplinary approaches are required to gain improved insight into the hydraulic fracturing performance. However, integration of different data sources is often not straightforward and requires innovative techniques.

This aim can be fulfilled by developing methods to capture the impacts of reservoir heterogeneity, most desirably in a quantitative manner, in a way that the results can be easily translated into reservoir dynamic modelling systems [14].

In addition to the importance of quantifying the heterogeneity impact on hydraulic fracturing, the need for more reliable means of production forecasting should also be thoroughly addressed. Production forecasting of hydraulically fractured wells is challenging, particularly for heterogeneous reservoirs where the rock properties vary dramatically over short distances, significantly affecting the performance of the wells. Despite the recent improvements in well performance prediction, the issue of heterogeneity and its effects on well performance has not been thoroughly addressed by the researchers and many aspects of heterogeneity have yet remained unnoticed [1]. Heterogeneity has been a serious challenge for production forecasting because it dramatically affects the productivity of wells and jeopardizes the development plan. This problem may deteriorate the economics of tight reservoir development because expensive stimulations strain the benefit margins. Modeling such stimulations and more reliable forecasting will lead to better understanding of the project outcomes [1].

Once a reliable production forecast scheme for hydraulically fractured wells is established, the feasibility of potential technically-approved hydraulic fracturing jobs need to be economically justified to facilitate decision-making on implementation of the project. Moreover, hydraulic fracturing economic evaluation at the low energy price era is more complicated and an appropriate decision-making process for such projects requires integration of technical forecasting including uncertainty analysis with economic models. Such models are very time consuming to implement if they include three-dimensional reservoir property variation [15]. Therefore, developing time-efficient methodologies for economic evaluations is of utmost importance as the last piece of the puzzle in prescribing reliable hydraulic fracturing practices for heterogeneous reservoirs.

1.3. Aims and Objectives of the Study

The process of hydraulic fracturing involves numerous subtleties and complexities even when considering the operations are performed in a homogeneous rock formation. Presence of heterogeneity, which is nearly always the case in reservoirs -albeit at different levels-, adds to the complexity of hydraulic fracturing, its performance evaluation, and prediction of the economic outcomes.

In this study, an attempt has been made to rigorously identify the main sources of complexities of the hydraulic fracturing in heterogeneous reservoirs from a practical standpoint in a systematic manner. Then, solutions have been proposed based on the key requirements of industry-acceptable approaches in modeling and evaluation of the fracturing performed. The main objectives of this research can be summarized in the following four areas:

1. Developing a comprehensive workflow for integration of the analysis task required of different engineering disciplines involved in design and evaluation of hydraulic fracturing

2. Developing a quantitative measure to the degree the hydraulic fracturing is influenced by heterogeneity of the reservoir rock

3. Devising a method for quantitative forecast of production from wells treated by hydraulic fracturing

4. Proposing an efficient economic risk evaluation method based on the outcomes of steps 2 and 3 to provide a complete picture of hydraulic fracturing evaluation.

1.4. Contribution to Knowledge

Hydraulic fracturing has gained increased attention and applicability in recent years due to its major role in production from tight reservoirs. As a result, research and development in hydraulic fracturing technology and modelling has advanced significantly to involve different disciplines of petroleum engineering and geoscience. The modeling approaches usually require input and feedback from numerous sources. One of the key points of focus in this research was developing roadmaps and workflows for integration of inputs, analyses, and feedback from the involved disciplines.

The already complex nature of hydraulic fracturing in terms of planning, operation, and particularly modeling and production forecasting becomes even more complicated in heterogeneous reservoirs. Heterogeneity has usually considered only qualitatively, and its impacts have often been somehow overlooked or underestimated. In this research, new parameters and approaches are proposed to deal with the effects of reservoir heterogeneity in a systematic and comprehensive way. In this regard, based on the properties of hydraulic fractures, the new parameter of HIF is proposed for quantification of the impact of reservoir heterogeneity on operation and outcomes of hydraulic fracturing.

The next technical gap identified in this research study was the lack of a reliable and robust method for performance prediction of hydraulically fractured wells. In this work, following the successful application of HIF, the DCH method is developed as an easy-to-implement technique for production forecasting of hydraulically fractured wells in presence of reservoir heterogeneity. This method can prove extremely helpful in cases where a dynamic model for the reservoir is not available or up-to-date. Even when reservoir simulation is an available option, the DCH method can be efficiently used as a cross-checking tool with simulation results.

Another important element in decision-making for hydraulic fracturing operations is the potential of economic success. Based on HIF analysis and DCH method results, an economic evaluation approach is proposed in this research where RCF is defined as a new parameter to evaluate the risk of commercial of failure of the hydraulic fracturing projects in heterogeneous reservoirs.

1.5. Thesis Framework

This thesis has been structured to address the main challenges associated with hydraulic fracturing, including the evaluation of reservoir heterogeneity impact, production forecasting of hydraulically fractured wells, and economic assessments in the following chapters and provide solutions accordingly. In this chapter (Chapter 1), an introduction to the subject of the study has been provided. Chapter 2 includes a comprehensive introduction to the hydraulic fracturing history as well as the process of hydraulic fracturing and its main elements, followed by an extensive literature review on the three main challenges related to hydraulic fracturing in heterogeneous reservoirs.

The proposed solutions to the challenges discussed are presented as the methodology in chapter 3, where, first, a new method is developed to diagnose the hydraulic fracture performance by integrating well test analysis and collecting data at each hydraulic fracturing stage. Then, an innovative technique is proposed for quantifying the impact of heterogeneity on hydraulic fracture performance as the Heterogeneity Impact Factor (HIF). In the next step, a novel empirical approach for production forecasting of multi-fractured horizontal wells is presented in an attempt to effectively include the effect of heterogeneity. This approach is based on the integration of hyperbolic decline curve analysis (DCA) and the previously proposed parameter, HIF. This novel, fast, and flexible method is called DCH and provides reliable well performance predictions for hydraulically fractured wells. It can also be used in forecasting undrilled wells and the range of possible outcomes caused by the heterogeneity. The last part of chapter 3 focuses on economic feasibility evaluation of hydraulic fracturing projects. Based on the methodologies developed for quantification of the heterogeneity impact on hydraulic fracturing performance through HIF and forecasting the production of hydraulically fractured wells through the DCH technique, a new parameter called the Risk of Commercial Failure (RCF) due to the impact of reservoir heterogeneity is introduced along with a rigorous workflow for economic evaluation.

Chapter 4 presents the application results of the proposed methodologies in a case study manner using the data from a real field in SNS. Where applicable, the results of the proposed techniques are validated using actual field data and evidences. Finally, conclusions of the study and the recommendations of the author for further work are outlined in Chapter 5.

Chapter 2. Literature Review

2.1. Introduction to Hydraulic Fracturing

Hydrocarbon resources have been broadly classified as conventional and unconventional. Conventional resources are found in sufficiently porous and permeable reservoir formations in which hydrocarbons are kept in place below a cap rock by buoyant forces and can readily flow into the drilled wells for sufficiently long periods of time (commercial production) [16]. However, unconventional resources are those that cannot be produced using the production methods applied to conventional reservoirs. Therefore, the types of hydrocarbon reservoirs that fall under the category of unconventional resources can change with time due to advances in exploration and production technologies, economic factors, and production scale and duration of these reservoirs. At present, gas and oil shales, tight sands, coalbed methane, heavy oil and tar sands, gas hydrates and fractured reservoirs are considered the main unconventional reservoirs whose porosity and permeability, mechanisms of fluid trapping, and other characteristics are different from conventional sandstone and carbonate reservoirs [16, 17].

Commercially viable production from unconventional reservoirs requires application of more advanced recovery solutions such as well stimulation treatments. One of the main well stimulation methods used particularly in gas and oil shales, tight gas sands, and coalbeds is hydraulic fracturing, also commonly referred to as fracking, which involves injection of pressurized liquid fluids, typically a mixture of water, chemicals, and sand slurry, into the wellbore to produce fractures in the reservoir rock and prop open passages, thereby enhancing the rock permeability to flow of hydrocarbons. However, the application of hydraulic fracturing is not limited to oil and gas production.

Other applications of the fracking technique include, but are not limited to, stimulation of groundwater wells [18], waste disposal by injection deep into rocks [19], underground stress measurements [20], and increasing injection rates for geologic sequestration of CO_2 [21].

2.1.1. Historical Notes

The practice of enhancing the permeability of reservoir rocks for improving the production from the wells dates back to the time of the earliest oil discoveries in the United States. Those initial well production enhancement techniques included the detonation of explosives such as dynamite or nitroglycerin use of down the wellbores [22]. In 1860s, Edward A. L. Roberts received a patent for an “exploding torpedo” which used nitroglycerin and was applied as a well stimulation method until 1990 [22]. As an alternative to use of explosives for well stimulation, acid fracturing in carbonates was introduced in 1890s in the United States [23] and gained commercial popularity in 1930s [24]. Acidizing enhances the flow of the well by producing fractures that do not close completely, as a result of acid etching [25].

Application of hydraulic pressure to induce fractures in the reservoir rock and increase the contact of a wells with the formation started in the late 1940s [26]. Following a study conducted by Floyd Farris of Stanolind Oil and Gas Corporation (later known as Pan American Oil Company) on the relationship between treatment pressure and well performance in acidizing, water injection, and squeeze cementing, the first experimental hydraulic fracturing job was performed by Stanolind in 1947 in the United States on a gas well in the Hugoton field in Grant County, Kansas [27, 25]. The low productivity of the well had not improved even after an acidizing job, and, therefore, it was selected for the first hydraulic fracturing operation to compare the performance of hydraulic fracturing with acidizing [27]. This hydraulic fracturing job did not prove very successful as the deliverability of the well did not improve markedly. However, it served as a start for future implementations and development of this technology [25].

In 1949, a hydraulic fracturing patent was issued with an exclusive license granted to the Halliburton Oil Well Cementing Company to perform fracking operations. In the same year, the first two commercial hydraulic fracturing jobs were performed by Haliburton in Stephens County, Oklahoma, and Archer County, Texas. The method became so popular in the United States that more 330 wells were hydraulically fractured in its first year of its commercial implementation resulting in an average 75% production increase. By mid 1950s, over 3000 wells a month were treated using the fracking technology [25].

Use of nuclear explosives to fracture tight gas reservoirs was experimented in the United States for the first time in 1967 in the San Juan Basin of New Mexico (the Gasbuggy Project). Such a practice was repeated in 1969 (the Rulison Project) and 1973 (the Rio Blanco Project) in the Piceance Basin of Western Colorado. However, this well stimulation technology did not gain any further popularity due to the poor production of the wells in the first three projects as well as the health-related concerns associated with radioactive contamination [28].

In an attempt to create very large fractures in the thick tight gas formations, massive hydraulic fracturing using 500,000 lbs of proppants was adopted by Pan American Petroleum Corporation in 1968 in Stephens County, Oklahoma [25]. typically, involved injection of over 300,000 lbs of proppants in hydraulic fractures of combined fracture wing lengths of 2000 to 4000 ft. Massive hydraulic fracturing proved successful for so-called “blanket” reservoirs where the tight gas formation is bounded above and below by shales with much higher resistance to fracturing than the target reservoir rock [28]. This hydraulic fracturing technique, however, does not work well in thick sequences of lenticular rocks in which the propagation of induced fractures does not have a predictable pattern and the gas flow rate may decrease as a result of proppant embedment into the interbedded shale layers [29].

In 1973, massive hydraulic fracturing was implemented by Amoco in Wattenberg Gas Field of the Denver Basin, Colorado to develop the very low-permeability gas-bearing Muddy J Sandstone. Although the initial smaller-scale hydraulic fracturing treatments in this field had resulted in increased gas production, the gas flow rates had declined rapidly rendering the small-scale fracking operations economically unsuccessful [30]. Since 1973, thousands of gas wells in the San Juan Basin, Denver Basin, the Piceance Basin, and the Green River Basin as well as other reservoir formations of the western United States were treated using the technique of massive hydraulic fracturing [28, 29, 31]. This technique was also used to produce from the wells in some otherwise uneconomic tight sands in Ohio, Pennsylvania, New York, Wyoming, Texas, and Louisiana [28]. In 1974, a massive hydraulic fracturing treatment with more than one million pounds of proppants was performed by Amoco in Wattenberg Field [32]. In the late 1970s, massive hydraulic fracturing was used to treat the wells in tight gas sands in other countries including Canada, Germany, and Netherlands, as well as the UK in North Sea [33].

Application of hydraulic fracturing was not limited to tight gas sands. This technology has also been used to develop shale reservoirs. First small-scale fracking operations in shale formations were implemented in 1965 in eastern Kentucky and southern West Virginia to increase the production from Ohio and Cleveland Shale formations [34]. From 1976 to 1992 some pilot hydraulic fracturing operations were conducted in the United States [35]. But, commercially successful application of hydraulic fracturing in shales started to grow in the late 1990s when slickwater fracturing using more water and higher pump pressures than before was utilized [36]. The combined application of the horizontal drilling technology with multistage hydraulic fracturing gained popularity following its success in increasing the oil production from the Austin tight chalk formation in Texas, United States, during early 1980s [37]. The first horizontal well was drilled in the in the Barnett Shale of Texas in 1991 which can be considered as a significant milestone in growth of shale gas industry and hydraulic fracturing development history [36].

According to the United States' Energy Information Administration (EIA) [38], hydraulically fractured wells have had an increasing share in the United States oil production as presented in Figure 1. According to the estimates presented by EIA in this figure, in 2015, over 50% of the United States' oil production has been from an estimated 300,000 hydraulically fractured wells producing over 4.3 million oil barrels per day (bbl/d), compared to production of over 100,000 oil barrels per day (less than 2% of the United States' production) from around 23000 hydraulically fractured wells in 2000. These figures show that hydraulic fracturing technology has grown significantly helping the United States to produce oil much faster than other time in the history.

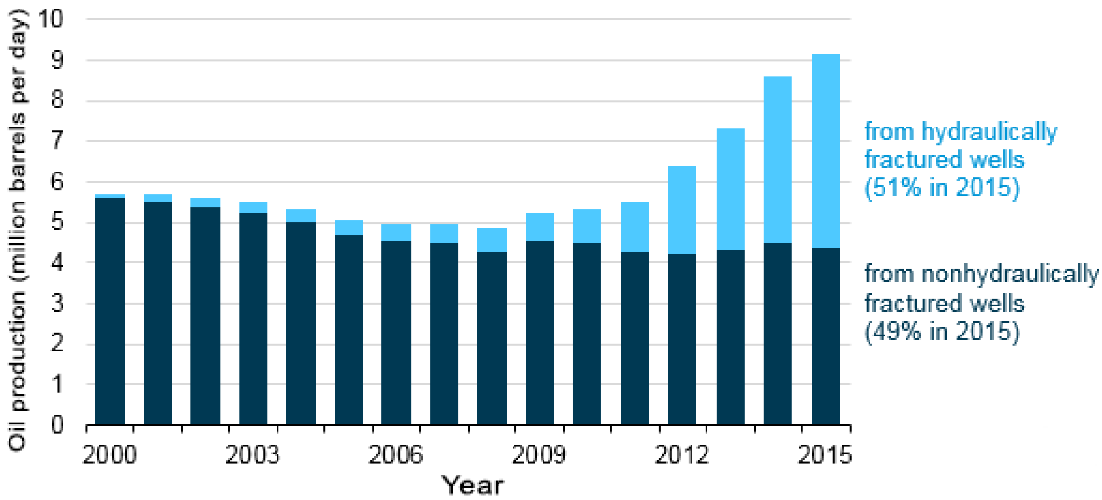

Figure 1. Oil production in the United States from year 2000 to 2015 [38]

The share of natural gas production using hydraulic fracturing in the United States has been even more significant than the share of oil production by this method. Today, most natural gas production in the United Sates comes from hydraulically fractured wells as the application of the fracking technique is no longer considered limited to unconventional resources. According to EIA estimates [39], in 2015, about two-thirds of the total marketed natural gas production in the United States was from the wells treated by fracking and this seems to be a growing trend. Figure 2 shows that, in 2000, around 3.6 billion cubic per day (Bcf/d) of marketed gas in the United States (less than 7% of the national total) was produced from about 26000 fracked wells, while these numbers increased to over 53 Bcf/d of natural gas production (about 67% of the national total) from an estimated 300,000 hydraulically fractured wells by 2015.

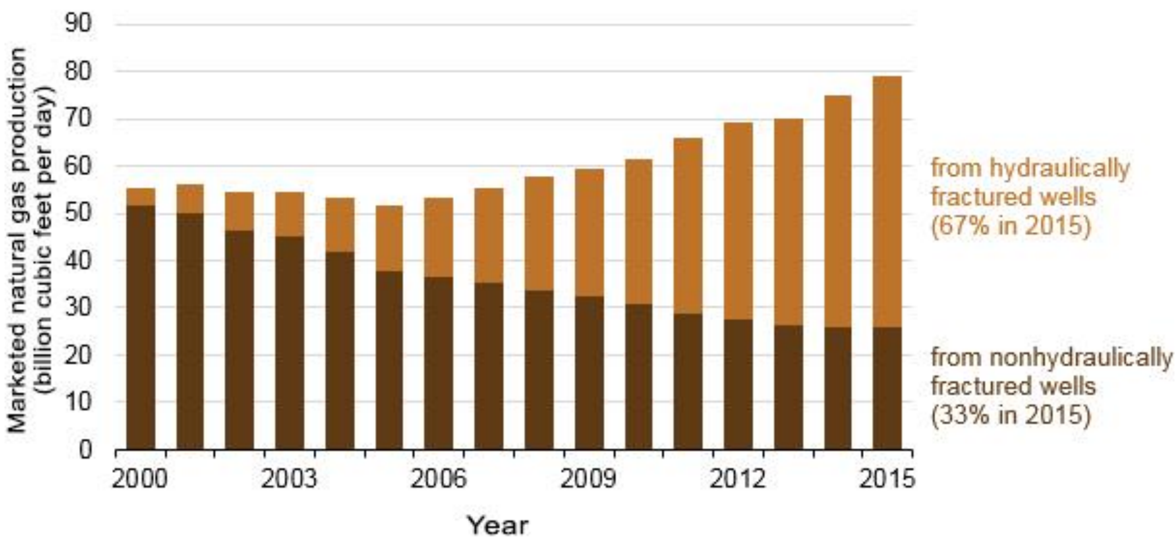

Figure 2. Marketed natural gas production in the United States from year 2000 to 2015 [39]

In the UK, the technique of hydraulic fracturing was first applied to an offshore well in West Sole field in the British Southern North Sea in 1965. Progressive evolution of the fracking technology in terms of massive hydraulic fracturing and invention of synthetic proppants made the application this technology more common in the North Sea offshore reservoirs. In 1980s, offshore fracking operations were performed using stimulation boats (starting in 1980) and fracturing vessels (from 1984 onwards). Massive hydraulic fracturing in the North Sea was made possible by the introduction of the high-capacity fracturing ships [33]. Numerous hydraulic fracturing operations have also been performed in conventional onshore reservoirs of the UK [40].

Other countries in which the practice of hydraulic fracturing has been reported include Australia, Canada, China, Germany, Netherlands, New Zealand, Poland, South Africa, and Ukraine [41].

2.1.2. Hydraulic Fracturing Process

Hydraulic fracturing is defined as a process to increase the extraction from a gas, oil, or geothermal well by pumping large volumes of fluids at extremely high pressure down a wellbore and into the target rock formation to create or restore fractures [42]. This process results in enhancing the permeability of the reservoir formations by creation of flow paths (fractures) for fluids towards the wellbore, improving the production by many hundreds of percent in some cases.

To create the hydraulic fractures, the fracking fluid is pumped into the cased wellbore at a rate that is sufficiently large to pressurize the formation downhole at the target perforations of well and break down the formation by exceeding the rock strength [43]. Once the formation break-down occurs and the fracture is initiated, the fracturing fluid permeates the rock and further extends the fracture. Most fracking operations are aimed at creating hydraulic fractures at perforations in the horizontally drilled sections of the wells. In such cases, a vertical fracture is ideally expected to be created in the form of two wings 180 degrees apart with similar shape and size. However, if the formation has natural fractures, the result of fracking may be multiple fractures and/or a bi-wing that propagates in a tree-like pattern with branches away from the perforations [44].

To prevent the closure of the hydraulic fractures due to in-situ stress after they are created, the fracturing fluid is mixed with proppants (e.g. sands or man-made ceramic materials) which keep the newly created fractures open for subsequent production from the treated well [44]. The fracking process is illustrated in Figure 3.

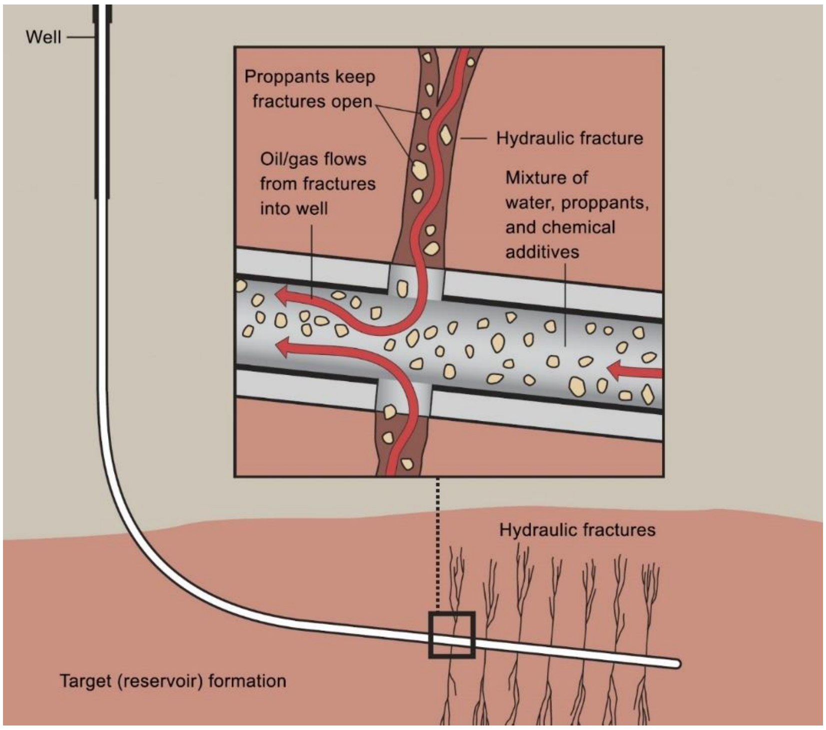

Figure 3. The process of hydraulic fracturing; modified after [45]

In general, the hydraulic fracturing operations may be performed in one of the following two forms:

- **Low volume hydraulic fracturing (conventional).** This form of fracking, also referred to as individual-well fracturing, typically involves injection of less than 80,000 gallons of fracturing fluid into a single well to remove the blockages and enhance the flow of fluids around the wellbore. Mostly performed on wells in conventional high-permeability reservoirs, low volume fracking is intended to remedy the permeability damage around the wellbore which occurs due to plugging of the pore spaces during drilling operations resulting in sealing off the borehole from the surrounding reservoir rock [46, 47].

- **High volume hydraulic fracturing (unconventional).** Also known as massive hydraulic fracturing, it is carried out in low-permeability unconventional reservoirs using much higher pressures (compared to low-volume hydraulic fracturing) to inject considerably larger volumes of fluid into the well to create fractures that reach hundreds of feet laterally out into the reservoir. In these treatments, often millions of gallons of water with various dissolved chemicals and millions of pounds of propping agents are mixed as the fracturing fluid [46].

The effectiveness of a fracking operation is generally assessed based on [26]:

- Orientation of the hydraulic fractures
- Areal extent of the hydraulic fracture system
- Enhancement of fluid (e.g. oil or gas) recovery as a result of the fracking job

A hydraulic fracturing job usually consists of the following stages [26]:

1. **Acid stage.** A mixture of several thousand gallons of water and a dilute acid (e.g. hydrochloric acid) is injected into the cased wellbore to clear the cement debris and open fractures near the wellbore by dissolving carbonate minerals. This stage may also be referred to the spearhead stage.

2. **Pad stage.** Around 100,000 gallons of slickwater (i.e. water with friction-reducing additives like potassium chloride to increase the flow and achieve higher pump rates) containing no solid material is injected into the wellbore to break down the target formation and open fractures

into the rock and make the fractures sufficiently wide for subsequent flow and placement of proppants.

3. **Prop sequence stage.** Several hundred thousand gallons of water containing non-compressible proppants such as fine sand particles or man-made ceramic material is injected, usually in several substages, down the wellbore to keep the hydraulically created and/or enhanced fractures open when the pressure is subsequently reduced during the fracking job. This stage may also be referred to the proppant stage.
4. **Flushing stage.** A sufficiently large volume of freshwater is pumped down the wellbore after the prop sequence stage to flush out any the excess proppant material present in the wellbore.

2.1.3. Fracture Patterns and Design

In vertical wells, hydraulic fracturing is often performed in a single interval. However, in horizontal wells, where there is considerable contact between the horizontal section of the wellbore and the reservoir formation, several discrete intervals may be fractured at separate fracturing stages. Indeed, each interval is isolated for its fracturing operation as specific sequences of additives might be required for each interval [26].

The following data are important in designing any fracturing operation [26]:

- In-situ stress profile
- Formation permeability
- Fluid loss characteristics
- Total fluid volume pumped
- Type and amount of proppant required
- Viscosity of the fracturing fluid
- Injection rate

- Formation modulus

The formations overlying and underlying the target zone must be characterised as their properties influence the growth of fracture height. It is also important to determine how the fracture length and fracture conductivity influence the productivity and ultimate recovery of the treated wells.

Selection of the suitable fracturing fluids is a very important aspect of the fracture design and is based on [48]:

- Reservoir temperature
- Reservoir pressure
- Expected value of fracture half-length
- Water sensitivity

In hydraulic fracturing operations to be performed in horizontals wells in low permeability shale gas formations, it is usually more desirable, regarding production benefits, to achieve transverse fractures than longitudinal fractures. However, achieving such transverse fractures is relatively more difficult. Transvers vertical fractures tend to extend normal to the direction of the minimum horizontal stress where the resistance is the least. In horizontal and deviated wells, the transverse fractures usually take tortuous paths in the immediate vicinity of the wellbore before they eventually achieve the direction normal to the minimum horizontal stress. This effect is more pronounced in reservoir formations with natural fractures or in cases where the horizontal section of the well has a deviation from the direction of the minimum horizontal stress [26].

For the hydraulic fractures to be initiated, the pressure at the target point should exceed the formation break-down pressure, which is the sum of the tensile strength of the rock and the in-situ stress. To extend a newly created fracture, the fracture propagation pressure should be achieved which is defined as the sum of the following:

- In-situ stress
- Net pressure drop
- Near-wellbore pressure drop

The net pressure drop is defined as the pressure drop down the fracture due to viscous flow in the fracture, plus any pressure increase resulting from tip effects. The near-wellbore pressure drop can be due to the combination of the pressure drop of the viscous fluid flow through the perforations and the pressure drop resulting from tortuosity between the wellbore and the propagating fracture. The properties of fracturing fluids are, therefore, of great importance in creation and propagation of hydraulic fractures in the reservoir formation [26].

The main factors that control hydraulic fracture nucleation and propagation include [26]:

- Local in-situ stress field
- Rock strength (stress level resulting in rock failure)
- Pore fluid pressure

Other factors which are influential in nucleation and propagation of hydraulic fractures are [49, 50, 51]:

- Elastic properties of the rock
- Temperature
- Pore water chemistry
- Loading rate

Considering rock mechanics, three types of fractures can develop in elastic rocks:

- Tensile fracture.
- Shear fractures
- Hybrid fractures (a mixture of tensile and shear fractures)

The ideal type of fracture in a hydraulic fracturing operation is the tensile fracture [52] where displacement of the wall rocks is perpendicular to the fracture surface as the shear stress is normal to the plane of the crack (See Figure 4). In contrast, shear fractures form when the displacement of fracture walls is tangent to the fracture plane. Wellbore breakout can occur due to shear fracturing in the form of conjugate fractures around the wellbore when the circumferential stress exceeds the rock strength due to drilling operations (See Figure 5).

For a tensile fracture to be created around a wellbore, the pore fluid pressure in the rock should be more than sum of the tensile strength of rock and the stress acting normal to the fracture plane. Formation of tensile fractures depends on geomechanical properties of the specific rock, shear and normal stresses, as well as pore fluid pressure. However, the fracture network created by hydraulic fracturing can be very complex and not easy to predict in detail [26].

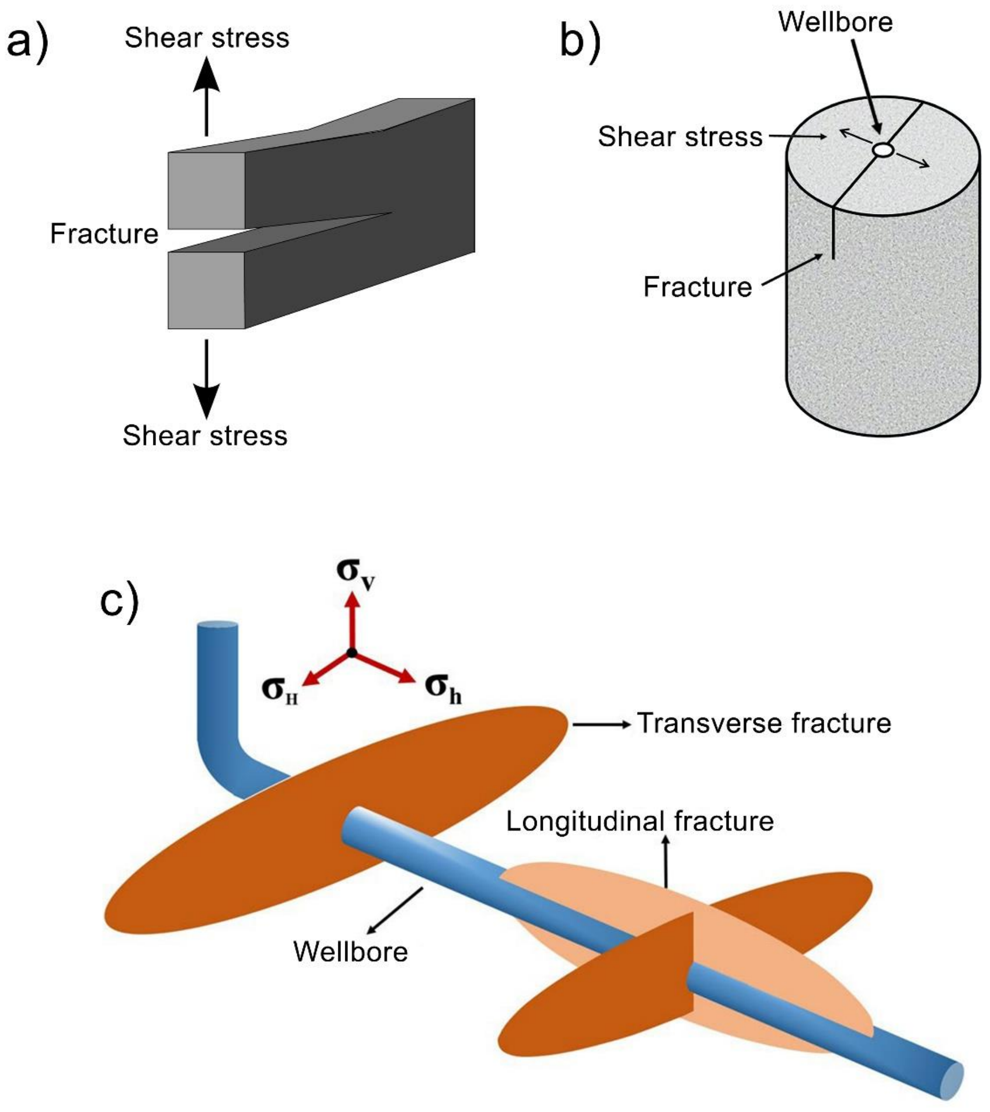

Figure 4. Creation of tensile fractures. (a) Dominant shear stress is normal to the plane of the fracture, modified after [53]. (b) Vertical tensile fracture in a vertical wellbore, modified after [54] (c) Tensile fractures created by hydraulic fracturing, modified after [55]; σ_V, σ_H, and σ_h show the direction of vertical in-situ stress, maximum horizontal in-situ stress, and minimum horizontal in-situ stress, respectively.

Well productivity optimization procedures used in hydraulic fracturing design are mainly based on optimization of the fracture size for which several approaches are available, each having their own limitations. The limitations of different hydraulic fracturing designs are due to the following factors [26]:

- Assumptions of fracture geometry
- Dependence of properties of reservoir and fracturing fluids

- Layered formations
- Stress intensity, etc.

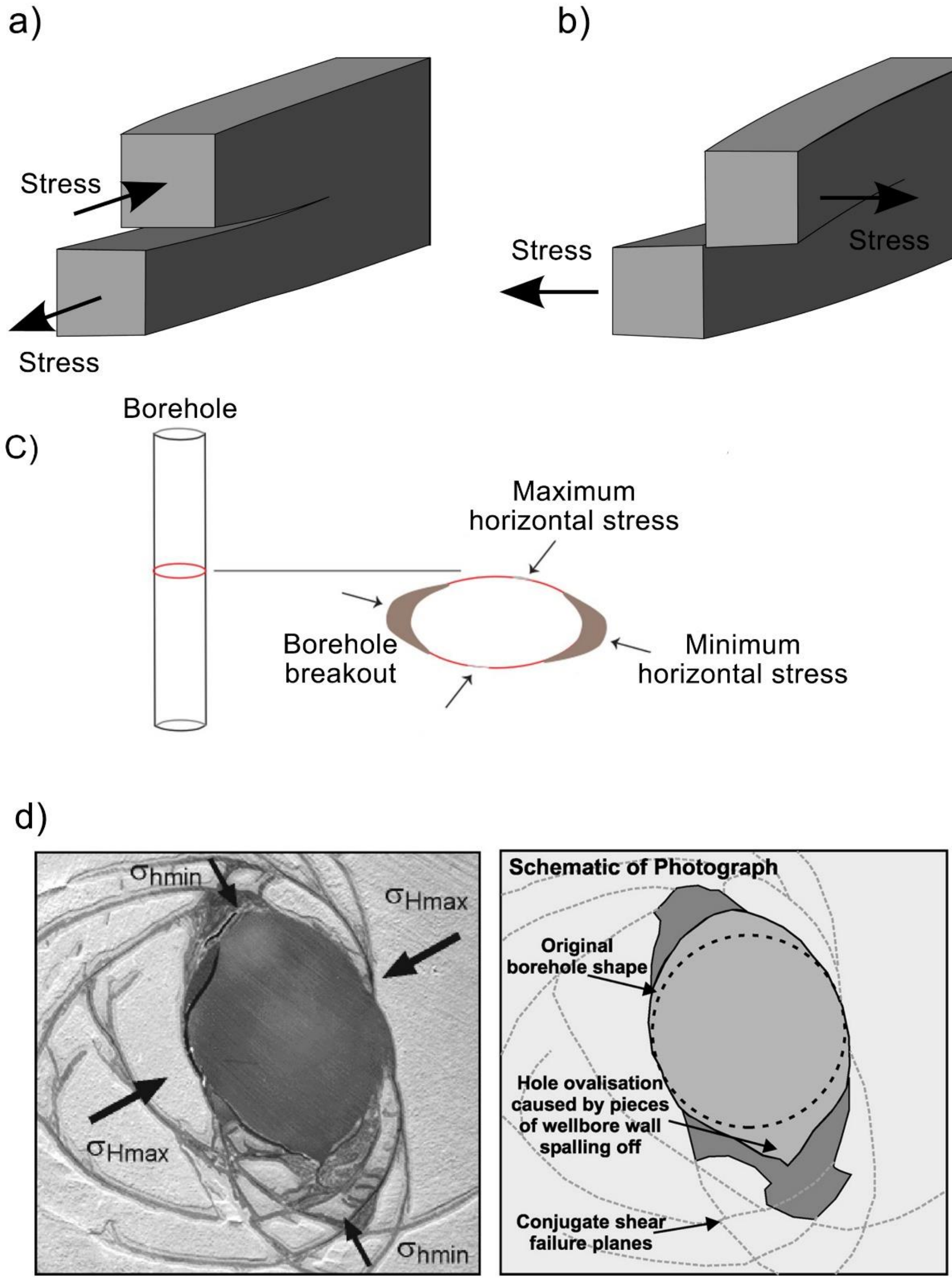

Figure 5. Shear fractures. (a) In-plane shear [53] (b) Out-of-plane shear [53] (c) Horizontal in-situ stresses and borehole breakout [56] (d) Borehole breakout; conjugate shear failure planes have resulted in ovalization of the cross-sectional shape of the wellbore [57].

Hydraulic fracture geometries can be discussed in terms of fracture orientation and length (or height) as described in the following sections.

2.14. Fracture Orientation

In general, the direction of hydraulic fractures is normal to the direction of the minimum stress. At depths less than approximately 2000 ft, the overburden pressure (σ_v) is typically not significant compared to horizontal in-situ stresses (σ_H and σ_h). Therefore, at such relatively shallow depths, hydraulic fractures tend to occur in a horizontal plane perpendicular to the direction the minimum horizontal stress (σ_h), that is parallel to the bedding plane. However, at depths greater than about 2000 ft, which is typical of most petroleum reservoirs, the overburden pressure is the dominant stress and the horizontal in-situ stresses are minimum and hydraulic fractures are usually oriented in the vertical direction, that is normal to the direction of the minimum horizontal stress [26, 52].

2.1.5. Fracture Length/Height

The extent to which a new hydraulic fracture grows is important for several engineering reasons, particularly regarding the growth of fractures out of the zones of interest as well as coverage of the reservoir thickness [52]. Fracture growth depends on the confining zone (or formation) boundaries as well as volume, rate, and pressure of the pumped fluid [26].

Considering an example of fracture growth in a formation with layered bedding (Figure 6), the growth of most of the fractures eventually stops at a bed boundary. Some fractures may continue growing to cross some bedding planes, but eventually terminate at some point.

Figure 7 schematically depicts two scenarios that may occur when a fracture is growing between bedding layers of different properties. This situation shown in this figure can be similar to cases where fracturing is occurring in a soft shale gas formation surrounded by the more brittle limestone layers. Stiffer layers generally exhibit higher horizontal stresses which tend to restrict the growth of fractures for a given fracture pressure as the net pressure acting on the fracture face will be smaller. Additionally, the fracture opening for a given pressure increase is less in stiffer rocks, allowing less fluid to be accommodated by the fracture. The combined effect of stress and compressibility results in limiting the fracture height/length growth. This explains why the fracture pinch-out occurs in conditions represented by case 2 in Figure 7.

The other possibility is complete termination of the fracture growth at the interface of the two layers (case 1 in Figure 7). In this case, the fracture cannot cross the interface due to either the mechanically weak bedding plane which allows independent movement of the two layers, or the insufficiently welded bedding plane or presence of thin laminations at the interface.

Another alternative to the two cases shown in Figure 7 is partial growth of the fracture along the interface. Both natural and hydraulic fracture growth can be hindered by composite layering in rocks combined with geomechanical variations [52].

In addition to the combination of geologic and geomechanical factors discussed above, pumping insufficient volumes of fracturing fluids in hydraulic fracturing operations and dispersion of pumping pressures certainly cause insufficient fracture growth due to natural attenuation of the fractures over short distances [26].

Figure 6. Interpreted fractures (red lines) within an outcrop, modified after [52]. Many fractures terminate at bed boundaries (yellow lines); none persist all the way from top to bottom of the section.

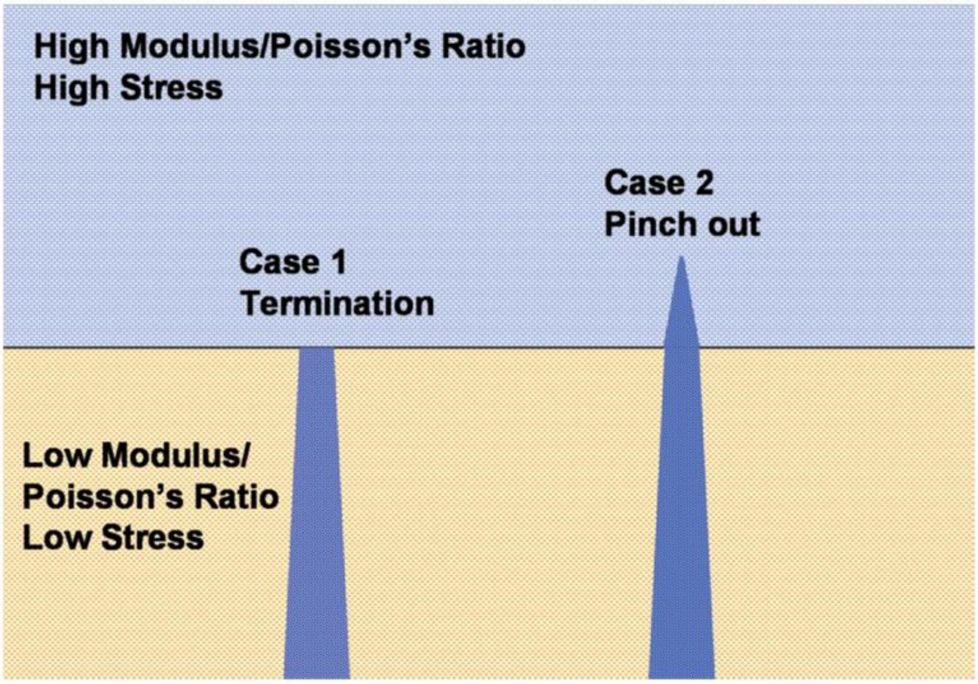

Figure 7. Schematic diagram of possible scenarios when fractures growth reaches the bedding interfaces [52]

The design of the hydraulic fracturing jobs should involve optimization of the following operational parameters [26]:

- Fracturing fluid viscosity
- Fracturing fluid injection rate and duration
- Proppant concentration, etc.

The final purpose of optimizing the above parameters is creation of a fracture geometry that results in the maximum recovery from the reservoir by increasing the sweep efficiency with the aid of the hydraulic fractures that connect the wells to most of the reservoir volume. Various approaches for optimization of fracture design used by different researchers include:

- Use of NPV as the economic criterion [58]
- Maximizing NPV using sensitivity-based optimization coupled with a fracture propagation model and an economic model [59, 60, 61]
- Mixed integer linear programming [62, 63]
- Ensemble surrogate methods (constructing NPV surrogates) [64]

However, optimization of hydraulic fracturing requires further rigorous studies due to uncertainties associated with geomechanical properties and of pre-existing fracture networks [64]. In summary, optimization of the fracture geometry involves designing the fracture half-length, width and conductivity in a way that the production from the hydraulically fractured wells is maximized, while the cost is controlled [26].

2.16. Fracturing Fluids

The main materials used in hydraulic fracturing are fracturing fluids and proppants. The fracturing fluid is the general term used for referring to the combination of a base fluid (e.g. water) and some additives. The fracturing fluids generally serve the following main purposes:

- Extending fractures
- Adding lubrication

- Changing the gel strength
- Carry proppants into the formation

The fracturing fluids used in the first hydraulic fracturing jobs were refined or crude oils mixed with gelling agents. These fluids were inexpensive and readily available, and their low-viscosity, and therefore less friction, allowed achieving the required injection rates at lower pumping pressures.

Water was first used in 1953 as a fracturing fluid. This was followed by several innovations such as development of a number of gelling agents, use of surfactants to minimize emulsions with the formation fluids, addition of potassium chloride to reduce the effect of fracturing fluids on clays and other water-sensitive formation materials, and development of other clay stabilizers. Further innovations that helped enhance the use of water as a fracturing fluid included foams and addition of alcohols [25].

Use of metal-based crosslinking agents to enhance the viscosity of gelled water-based fracturing fluids was one of the significant innovations in the early 1970s which facilitated performing hydraulic fracturing operations in higher-temperature wells. These high-temperature jobs also required gel stabilization for which methanol was used initially, followed by development of chemical stabilizers which could be used with or without methanol. Later improvements in crosslinkers and gelling agents further facilitated high-temperature fracking.

More recent improvements in this field include ultraclean gelling agents based on surfactant-association chemistry and encapsulated breaker systems that activate upon fracture closure to minimize fracture-conductivity damage. Currently, more than 90 percent of all the fracturing operations use aqueous fluids such as water, brine, and acid [25].

2.1.7. Properties of Fracturing Fluids

The fluids used in different hydraulic fracturing operations vary from site to site and the choice of the appropriate fluid, required fluid volumes, and injection rates are based on formation geology, production characteristics of the field, and economic factors [26]. Any fracturing fluid is expected to have the following general properties [65]:

- **Low leak-off rate.** This property is usually achieved by adding additives that control the loss of hydraulic fracturing fluid.
- **Proppant transporting capability.** Density, viscosity, and flow velocity of the hydraulic fracturing fluid control its proppant transporting capacity. Viscosity has the most influence on transport of propping agents and the fracturing fluid is usually thickened by adding viscofiers.
- **Low pumping friction loss.** This property is also controlled by adding appropriate additives to the fracturing fluid.

In addition to the properties mentioned above, ideally, the fracturing fluid should also be able to create fractures with adequate width, maximize the fluid travel distance for achieving sufficient fracture length, and require minimal gelling agent to allow for easier degradation or breaking [26].

Success of a hydraulic fracturing job depends on several variables not all of which can be easily controlled. The variables that are controllable include the properties of fracturing fluids, the injection rate, and the quality of proppants [66]. Therefore, effective design of the fracturing fluid is of utmost importance.

Generally, the simplest and most cost-effective fluids used in hydraulic fracturing are water-based fluids. However, waterless fracturing treatments are preferred in many cases because of the issues associated with the use of water as the fracturing fluid. These issues can be summarized as follows [67, 68]:

- **Water sensitivity of the formation.** Use of water for fracturing formations with particular mineral composition can result in adverse effects such as clay swelling, migration of fines, and drop of proppant conductivity in many shale formations due to softening of the rock in presence of water.
- **Water blocking.** In undersaturated gas reservoirs, water injected as the fracturing can remain trapped due to capillary retention. This water trapping or water blocking may significantly reduce the relative permeability to gas upon the increase in water saturation.
- **Proppant placement.** Use of slickwater in hydraulic fracturing is much less effective than foams and other gelled non-aqueous fluids in transporting the propping agents. Foams with higher volumes of gas exhibit higher effective viscosities due to interaction between gas bubbles, and therefore better proppant transporting capacity.
- **Water availability and cost.** Use of water as the fracturing fluid is limited in some areas due to shortage of freshwater or local legislations against the use water in hydraulic fracturing treatments.

Hydraulic fracturing operations may generally be described as either high-rate or high-viscosity treatments. High-rate treatments involve injection of low-viscosity slickwater with low proppant concentrations at high pump rates to create narrow complex fractures. This method has recently been largely applied to shales in the US. Pump rates should be sufficiently high so that the proppants can be transported over long distances in horizontal wells without screening out of the fluid prematurely before entering the hydraulic fractures. High-viscosity treatments, however, are intended to transport a larger quantity of propping agents. The pumps rates are, therefore, lower due to high viscosity of the fracturing fluid and the resulting fractures are larger and wider [26].

Fluid density is also an important property in hydraulic fracturing operations. Surface injection pressure and the ability of the fluid flow back after the treatment is influenced by the fluid density. The density of water-based fluids is typically around 8.5 pounds per gallon. Oil-based fracturing fluid exhibit densities in the range of 70% to 80% of the water-based fluids. Foam-based fluids are considerably less dense than water-based fluids and can be used in low-pressure reservoirs to assist in the fluid clean-up. However, in deeper reservoirs with higher pressures (e.g. offshore reservoirs), higher-density fluids may be required [26].

Considering the fracturing fluid as mixture of the base fluid, proppants, and chemical additives, the latter constitutes only 0.5% to 2% of the total volume of the fracturing fluid, while the base fluid and proppants make up about 98% to 99.5% of the total volume. The proppants usually constitute around 9% to 9.5% of the total volume of the hydraulic fracturing fluid [26].

2.1.8. Types of Fracturing Fluids

Design of the hydraulic fracturing fluid is a crucially important task not only from the technical standpoint, but also from the environmental aspects in terms of the use of chemical additives and flowback treatment [26]. Fracturing fluids are generally classified according to the base fluids as water-based fluids, foam-based fluids, acid-based fluids, alcohol-based fluid, emulsion-based fluids, and other fluids such as liquified gases [69, 70, 71, 72]. These fluid types are briefly introduced in this section with a summary provided in Table 2.

Table 2. Fracturing fluid types and varieties [43]

Fluid type	Varieties	Main composition
Water-based	Slickwater	Water + sand (+ chemical additives)
	Linear	Gelled water, GUAR, HPG, HEC, CMHPG
	Crosslinked	Crosslinker + GUAR, HPG, CMHPG, CMHEC
	Viscoelastic surfactant gel	Electrolyte + surfactant
Foam-based	Water-based foam	Water and foamer + N_2 or CO_2
	Acid-based foam	Acid and foamer + N_2
	Alcohol-based foam	Methanol and foamer + N_2
	CO2-based foams	Liquid CO_2 + N_2
Oil-based	Linear	Oil, gelled oil
	Crosslinked	Phosphate ester gels
	Water emulsion	Water + oil + emulsifiers
Acid-based	Linear	
	Crosslinked	
	Oil emulsion	
Alcohol-based	Methanol-water mix	Methanol + water
	Methanol	Methanol
Emulsion-based	Water-oil emulsion	Water + oil
	CO_2 -methanol	CO2 + water + methanol
	Other	
Cryogenic fluids	Liquid CO_2	CO_2
	Liquid nitrogen	N_2
	Liquid natural gas	LPG (butane and/or propane)

A. Water-based Fluids

Slickwater, linear fluids, cross-linked fluids, and viscoelastic surfactant fluids are the main water-based fracturing fluids.

Slickwater. Over 98% of slickwater is water and sand. Other chemicals are added for different purposes such as reduction of friction, corrosion, and bacterial growth, as well as wettability alteration and scale inhibition [26, 43]. Low viscosity of slickwater results in more complex fracturing networks with lesser fracture width and greater fracture length, but limited proppant transporting capacity. Therefore, high pump rates are required to overcome premature proppant settling. Slickwater treatments are more commonly implemented in unconventional gas reservoirs [43]. The high pumping pressures required in slickwater treatments are moderated by adding friction-reducers that are up to 70% efficient, facilitating pump rates in the range of 60 to 100 barrel per minute. Examples of friction-reducing additives include acrylamide derivatives and copolymers. The main advantages of slickwater fracturing include [26, 43]:

- High retained conductivity due to formation of no filter cake
- Reduced sensitivity to salinity and contaminants in mix-water
- Less additive requirements
- Reduced gel damage
- Higher stimulated reservoir volume
- Better fracture containment.

Some disadvantages of the use of slickwater as the fracturing fluid are [26]:

- Excessive volumes of water required
- Large horsepower required for high pump rates
- Limited fracture width resulting low concentrations of proppants
- Heavy losses of fracturing fluid in the complex fracture network resulting in low water-flowback recoveries
- Limited maximum proppant size due to reduced proppant transport capacity of the low-viscosity fluid.

Linear fluids. When fracturing fluids with higher viscosities are required for improved proppant suspension, various polymers as dry powders may be added to water to form non-crosslinked linear fluids. Such polymers include guar, Hydroxypropyl Guar (HPG), Hydroxyethyl Cellulose (HEC), Carboxymethyl hydroxypropyl guar (CMHPG), and Carboxymethyl Hydroxyethyl cellulose

(CMHEC) [73]. These powders swell when in aqueous solutions and form gels with viscosities higher than slickwater. In low-permeability formations, linear gels can control fluid loss effectively, but reduce fracture conductivity by forming thick filter cakes on rock surfaces. These effects are the opposite in formations with higher permeabilities [43]. Linear fluids may be used in manner referred to as hybrid fracturing to overcome some of the disadvantages of slickwater fracturing. In hybrid fracturing, linear fluids with viscosities of several orders of magnitude higher than slickwater are pumped as late-slurry stages following the injection of slickwater in the pad and early-slurry stages [26].

Crosslinked fluids. These fluids have been developed to improve the performance of gelling polymers without increasing their concentration. A crosslink is a bond that links one polymer chain to another and “crosslinking” is the use of crosslinks to promote a difference in the physical properties of polymers. Borate crosslinked gel, crosslinked guar gum, and organometallic crosslinked fluids are the most common types of fracturing fluids in this category. Borate crosslinked gel fracturing fluid is obtained using borate ions to crosslink the hydrated polymers (most often guar and HPG) to increase the fluid viscosity. Using borate ions, formation of the crosslink is triggered by altering the PH of the fracturing fluid and its reversible characteristic facilitates effective clean-up, and therefore, good permeability and conductivity [26, 43]. Borate crosslinked gel fluids which are highly effective both in the low-permeability and high-permeability formations, offer the following advantages [43]:

- Efficient proppant transport
- Stable fluid rheology at temperatures up to 150 ˚C
- Low fluid loss
- Good clean-up properties.

Crosslinked guar gum is a common fracturing fluid for environmental applications. The most widely used form of guar gum is called continuous mix grade which hydrates and reaches the desired viscosity so rapidly that it can be used continuously. Due to its high viscosity, guar gum is suitable to carrying coarse-grained propping agents into the fractures using pumps which are specifically designed for high-viscosity fluids containing high proportions of solid material [26, 65, 74]. HPG and CMHPG are two examples of guar gum chemically modified to exhibit certain useful properties. Similarly, HEC and CMHEC are natural source water-based fracturing fluids derived from cellulose. These derivatives work effectively in the temperatures ranging from 18 to 205 ˚C. For temperatures higher than 107 ˚C, though, chemical stabilizers such as methanol or thiosulfate need to be added to the slurry to prevent loss viscosity due to decomposition [26, 75].

Organometallic crosslinked fluids such as zirconate and titanates complexes of guar, HPG, and CMHPG are also commonly used in tight sand gas reservoirs where extended fracture lengths are required. Advantages of these fluids include [26]:

- Stability at high temperatures
- Proppant transport capability
- Predictable rheological properties

Viscoelastic surfactant (VES) gel fluids. These fluids are primarily composed of surfactants combined with inorganic salts to create ordered structures with increased viscosity and elasticity. Due to their high zero-shear viscosity, VES gel fluids can carry proppants with lower loading and without the comparable viscosity requirements of other conventional fracturing fluids. Based on the structure created by the fluid system, VES gels can be categorized as wormlike micelles, lamellar structures, and vesicles. Some advantages of VES gel fluids include [26]:

- Requiring no biocides due to containing no biopolymers
- Requiring no additional flowback surfactants because of their inherently low surface and interfacial tension
- No need to additional clay control additives

B. Foam-based Fluids

Foam-based fluids can be the preferred choice of hydraulic fracturing fluid in cases of water-sensitivity of the formation or scarcity of water in the area [76, 77, 78]. Foams are structured two-phase fluids that are formed by dispersion as small discrete entities of a large internal phase volume (typically 55 to 95%) through a continuous liquid phase [79]. Foams are generally characterized by their quality and texture. Foam quality is defined as the gas fraction in the total gas and liquid mixture and foam texture is defined as the number of bubbles in unit mixture volume. These two characteristics control the viscosity of the foam [80].

Use of foams as the fracturing fluid results in less fluid to recover and handle after the treatment. Moreover, expansion of the gas phase of the foam after the process facilitates the recovery of the liquid phase introduced into the formation with foams [80]. The advantages of foams can be summarized as [43]:

- Reduced water usage (or completely eliminated in case of CO2-based foams)
- Reduced amount of chemical additives
- Reduction of formation damage
- Better clean-up of the residual fluid.

Potential disadvantages of using foams as the fracturing fluid include [43]:

- Low proppant concentration in fluid, hence decreased fracture conductivity
- Higher costs
- Difficult rheological characterization of foams making it difficult to predict the flow behaviour
- Higher surface pumping pressure required.

The main types of foam-based fluids used in hydraulic fracturing operations include water-based foam (i.e. water and foamer + N_2 or CO_2), acid-based foam (i.e. acid and foamer + N_2), alcohol-based foam (methanol and foamer + N_2), and CO_2-based foams (liquid CO_2 + N_2) [43].

C. Oil-based Fluids

Oil-based fluids were the first fracturing fluids used for hydraulic fracturing. They offer advantages such as high viscosity and being compatible with almost any rock formation. However, potential high costs as well as greater safety risks and environmental issues compared to water-based fluids can be considered as disadvantages of oil-based fluids [43].

For over half a century, liquified petroleum gas (LPG) has been used for fracturing conventional and unconventional reservoirs. Gelled LPG, primarily propane, has gained extensive use in stimulation of shale rocks in Canada and the United States since 2007. Liquified butane and propane can also be used for fracturing specific rock types. Gelling agents such as dialkyl phosphate ester and crosslinking agents such as a ferric complex can be added to LPG for improved performance in unconventional reservoirs. Gelled LPG has several advantages [43]:

- Consistent viscosity
- No addition of CO_2 or N_2 is required, thus reducing costs
- No cooling or venting equipment is required

LPG is abundantly available as a by-product of the natural gas industry and its use offers other advantages such as easy storage at ambient temperature and reduction of CO_2 emissions due to the reduced need to flare production for clean-up purposes [43].

Further technological advances of LPG-based fracturing fluids were made by developing new formula for the fracturing fluid containing pure propane and sand with no chemical additives. Propane volumes in this type of fluid were also reduced to meet stricter safety requirements [81].

Recently, a non-flammable, non-toxic shale stimulation fluid has been developed using naturally occurring components in conventional and shale hydrocarbon production, i.e. a selection of light alkanes. These alkanes are non-flammable, non-toxic for human ingestion and exposure, and have no adverse impacts on the environment in terms of ozone depleting and global warming. In this technology, LPG, instead of being gelled, is mixed with buoyant proppants such as fine sand and carbon fullerenes. During the fracturing, LPG remains liquid, but is dissolves in the reservoir gas once the treatment is completed [82].

D. Acid-based Fluids

The main difference between acid fracturing and hydraulic fracturing using proppants is that acid fracturing assists the flow of the hydrocarbons from the wells by "etching" channels in the rock that constitute the walls of the fracture. However, not all rock formations can be treated by acid and acid fracturing can only be applied to rocks which are partially soluble in acid. Therefore, the technique is mainly applied in some carbonates. Shale formations also typically contain carbonate and limestone, but these do not form a continuous body sufficiently large to create continuous acid-etched channels in the shale formation. In acid fracturing, it is usually difficult to obtain long etched fractures due to rapid reaction of the acid with the formation as well as high leak-off. Moreover, proper disposal of the flowback is difficult as it contains large volumes of dissolved carbonates [43].

Acid penetration in the formations can be improved using better acid fracturing mixtures [83]. Hydraulic jet acid fracturing technique [84] can be used for deeper carbonate reservoirs where high temperature, high fracture pressure, high flow friction, and strong reservoir heterogeneity present severe challenges [43]. A more recent technique has proposed CO_2-assisted acid fracturing in tight gas carbonates reservoirs [85]. Using CO_2 to assist and to the stimulation fluid has the following advantages:

- Elimination of potential formation damage normally associated with fracturing fluids
- Reduced water and acid required compared to conventional acid fracturing
- Very rapid clean-up
- Increased well productivity

E. Alcohol-based Fluids

Use of methanol-based fluids in hydraulic fracturing was mainly practiced in the last decade of 20th century [86]. A review of hydraulic fracturing methods shows that in recent years methanol has rarely been used a base fluid in fracturing and its use has been limited to that of an additive [87].

Methanol-based fluids have been used in formations with low permeabilities. Non-aqueous methanol-based fluids can be the only effective fracturing fluids in formations with severe liquid trapping issues or irreducible water and/or hydrocarbon [88].

The advantages of alcohol-based fracturing fluids include [43, 89, 90, 91]:

- Low freezing point
- Low surface tension
- High solubility in water
- High vapor pressure
- Compatibility with formations with clay contents
- Effective recovery in formations with irreducible water and/or hydrocarbon saturation
- Reduced or complete elimination of water usage
- Rapid biodegradation of methanol under both anaerobic and aerobic conditions and relatively rapid photodegradation

Limited use of methanol-based fracturing fluids is mainly due to safe handling issues and associated additional cost. These disadvantages can be summarized as follows [87]:

- Low flash point, hence easier to ignite
- Large range of explosive limits
- High vapor density
- Invisibility of the flame

During the period methanol was being used as a base fluid for fracturing, its viscosity was increased in several ways including making methanol-based foam and gelling the methanol using synthetic polymers and guar gum. Successful field application of gelled methanol crosslinked with metal crosslinkers has also been reported [92].

F. Emulsion-based Fluids

An emulsion is a mixture of two or more miscible fluids. Most of the emulsion-based fluids are composed of oil and water and may be classified under oil-based or water-based fluids [43]. First field application of emulsion-based fluids in hydraulic fracturing dates back to 1981 when an emulsion of CO_2 in aqueous alcohol-based gel was used successfully in western Canada. The main advantage of emulsion-based fluids is that they minimize or even completely eliminate the use of water [93].

Emulsion-based fluids increase well productivity, exhibit better rheological properties, are compatible with shale formations, and depending on their formulation require fewer or no chemical additives. These fluids are particularly suitable for low-pressure tight gas formations. The downside of emulsion-based fluids, however, is their relatively high costs compared to water-based fracturing fluids [43].

G. Cryogenic Fluids

Cryogenic fluids include liquid CO_2, liquid nitrogen, and liquid natural gas. CO_2 can be used instead of water in hydraulic fracturing. It may be pumped as pure CO_2 or mixed with N_2 to reduce costs. CO2-based fluids have been very successfully used in tight gas formations in Canada and the United States [43]. Use of CO_2 as an additive in hydraulic and acid fracturing started in the early 1960s [94]. However, it was in 1981 that the use of liquid CO_2 was considered as a fracturing fluid [95]. Liquid CO_2 mixed with proppants is injected down the wellbore using high pressure pumps. During the flowback, upon reduction of pressure, CO_2 turns into gas and reaches the surface [43].

Fracturing can also be performed using supercritical CO_2 as suggested by some recent studies [96, 97, 98, 99, 100]. Above its critical point (31.1°C and 7.39 MPa), CO_2 can be held at the supercritical fluid state which makes CO_2 capable of achieving a higher penetration rate with no additional damage in shale reservoirs [43]. CO_2 can also be injected in conjunction with other fluids in fracturing operations that use a hybrid system [101].

The fracture networks created using CO_2-based fluids are typically much more complicated due to lower viscosity of CO_2; this is favourable in shale gas exploitation [96, 97]. The main advantages of CO_2-based fracturing can be summarized as follows [43, 102]:

- Reduced or completely eliminated use of water
- Few or no chemical additives required
- Reduction of formation damage by reverting to a gaseous phase as well as clay swelling induced
- Increased fracture conductivity due to development of complex microfracture networks
- Enhanced gas recovery by displacing the methane adsorbed in shale formations
- Rapid clean-up facilitating immediate evaluation of the fractured zone
- Elimination of all residual liquid left in the formation from the fracturing fluid
- Enhanced lifting of the produced fluids by the CO_2 gas during the clean-up operation
- Adding no pollution to the environment and reducing the problems associated with emission of greenhouse gases
- More controlled proppant placement due to low viscosity of CO_2 and higher proppant placement within the created fracture

An alternative to liquid CO_2 is the use of supercritical CO_2 as the fracturing fluid which offers the advantages of superior stimulation capability and less equipment required due to lower fracturing pressure compared to liquid CO_2 fracturing [100].

Despite its several advantages, use of CO_2 has a number of associated drawbacks including [43, 100]:

- High friction of liquid CO_2
- Lack of suitable drag reducers
- Poor proppant carrying capacity of liquid CO_2 due to its low viscosity
- Decreased fracture conductivity due to use of lower concentrations of proppants with smaller sizes
- High fluid loss during the fracturing
- Lack of precise prediction methods due to complicated phase behaviour changes of CO_2
- Under-pressure storage and transportation of CO_2
- Corrosive nature of CO_2 in presence of H_2O
- Potentially high treatment costs

Hydraulic fracturing can also be performed by pumping liquid N_2 down the wellbore, particularly in shale formations that are under-pressured and sensitive to other fluids. N_2 is typically used in its gaseous form mixed in other fracturing fluids as follows [43]:

- Mists: 95% N_2 carrying a liquid phase
- Foams: 50%-95% N_2 foamed within a continuous liquid phase
- Energized fluids: 5% to 50% N_2 mixed with a base fluid

A very important aspect of using liquid N_2 in fracturing is a thermal shock that occurs as the extremely cold liquid N_2 (-185˚C to -196˚C) comes into contact with the warm rock, resulting in creation of self-propping tensile fractures. As the fluid's temperature rises to the reservoir temperature, it turns into gas and its flow rate increases significantly [103]. The advantages of liquid N_2 fracturing include complete elimination of water usage, use of no chemical additives, and reduction of formation damage. However, safety and handling of liquid N_2 is costly and special equipment is required. Moreover, since the N_2

turns into gas as it heats up while travelling down the wellbore, it cannot carry proppants into the fractures [43].

Another cryogenic fluid reported in the literature is cryogenically processed natural gas extracted from nearby wells of the same formation and cooled and compressed at the wellsite. The resulting cold compressed natural gas (CCNG) is pumped down the wellbore with proppants carried in foam-based fluid system. After fracturing and placement of proppants, the natural gas used in fracturing is produced at the surface again, hence resulting in no economic loss. Besides, this technique eliminates the use of water and chemical additives [104].

2.1.9. Additives

Additives usually constitute about 0.1% to 0.5% of the total volume of the fracturing fluids and are added to make the fluid achieve specific properties and overcome its inherent limitations [70, 71, 72, 105]. The type and number of additives used in the fracturing fluid depend on well conditions and the base fracturing fluid as well as the characteristics of the rock formation surrounding the well which is being fractured. Typically, 3 to 12 additives are added to the fracturing fluid [43].

Generally, additives are intended to enhance fracture creation and reduce formation damage. Additives that enhance the creation of fractures include viscofiers, temperature stabilizers, pH control agents, and fluid loss controllers. Additives which are used to reduce formation damage include gel breakers, biocides, surfactants, clay stabilizers, and gases [75]. Other additives which are used in fracturing operations include scale inhibitors, ion control agents, corrosion inhibitors, oxygen scavengers, gelling agents, and crosslinking agents [43].

Fluid-loss additives. Fluid loss in hydraulic fracturing occurs as the fracturing fluid leaks off the fracture into the formation rock. Uncontrolled loss of fluid may result in a "proppant bridge", i.e. an increase in concentration of proppants around the wellbore, thereby stopping fracture propagation [75]. The purpose of fluid loss additives, which are largely insoluble micron-sized particles dispersed into the fracturing fluid, is to restrict the leak-off rate and maintain the effective volume of the fracturing fluid to facilitate propagation of larger and deeper fractures [75, 106]. Once fracturing starts, some fluid is immediately lost to the formation ("spurt loss") and the fluid-loss additives form a filter cake on the fracture walls restricting further leak-off. During the flowback period, this filter cake re-disperses and flows out of the fracture. The fluid-loss additive is expected to coat the fractures and restrict further fluid loss as well as to prevent excessive spurt loss. Fluid-loss additives include bridging materials such as 100-mesh sand and 100-mesh resin, or plastering material such as starch blends, talc, silica flour, and various clay minerals [43].

Clay stabilizers. Swelling of clay minerals present in reservoir rocks, particularly shale formations, is a common challenge that can drastically impede the flow of fluids inside the rock. Clay swelling occurs due to the ionic shock upon contact of clay minerals with water where the cations present at the base-exchange positions or sites within crystalline layers of clay minerals get solubilized, resulting in instability of the clays that may be manifested in swelling [43, 107]. Clay stabilizers prevent clay swelling through ion exchange by providing cations to replace the solubilized clay cation. The main clay stabilizers include inorganic salts such as potassium chloride (KCl), sodium chloride (NaCl), and ammonium chloride (NH_4Cl). Polymeric clay stabilizers may also be used which act by attaching anions to the clay surface to restrict the migration of fines [43, 75].

Gel breakers. Once the hydraulic fractures are created in the rock and the proppants are placed in the fractures, the viscosity of fracturing fluid should be reduced in order to minimize return of proppants and maximize return of fracturing fluid to the surface during flowback. This task is performed by adding gel breakers to fracturing fluid during the pumping period or introducing them separately later. When active, gel breakers degrade the viscosity of fracturing fluid by reducing the molecular weight of the gelling polymers used and allowing them to flow out of the fractures to the surface. The three main types of gel breakers used in hydraulic fracturing include [43]:

- ***Oxidizers*** work by cleaving acetyl linkages in the polymer backbone, breaking the polymer into its constitutive sugars. These oxidizers include ammonium persulfate ($(NH_4)_2S_2O_8$), sodium persulfate ($Na_2S_2O_8$), calcium peroxide (CaO_2), and magnesium peroxide (MgO_2).
- ***Acids*** such as hydrochloric acid (HCl) or acetic acid (CH_3COOH) attach the polymer backbone and break the polymer into its constituents in a similar manner to the oxidizers function, the main difference being less selectivity of acids which may cause considerable amounts of insoluble materials to be formed. Acid can also work by reversing the crosslink in borate-crosslinked fluids [75, 108].
- ***Enzymes***, which are protein molecules such as hemicellulose, cellulase, amylase, and pectinase, function as organic catalysts that attach and digest polymers at specific sites of the polymer backbone. These enzymes are only effective at mild temperatures below 66˚C and fluid pH between 4 and 9. Guar linkage-specific enzymes can be used at higher temperatures (up to above 150˚C) [109].

Biocides. When organic polymers are used in fracturing fluids, the fluid can become a medium for growth of bacteria which secrete enzymes that act as gel breakers and reduce the viscosity of fluid, negatively affecting proppant placement. If untreated, such fluids can trigger bacterial growth in the reservoir and lead, for example, to generation of hydrogen sulfide (H_2S) gas [65]. Therefore, biocides, bactericides, or microbicides are usually required to be added to the mixing tanks containing gelling agents. Quaternary amines, amide-type chemicals, and chlorinated phenols are some of the biocides used to prevent bacterial growth issues [43, 65].

PH control. Several properties of the fracturing fluids including polymer gelation rate, crosslinking characteristics, gel break properties, bacterial growth, and viscosity stability are affected by the fluid pH which typically ranges from 3 to 10. The appropriate pH is maintained by adding buffers made from weak acids and weak bases [43, 75].

Friction reducers. A direct result of increasing the viscosity of water-based fracturing fluids is increasing frictions in the system. To maximize the pumping pressures and rates, friction should be minimized. Therefore, friction reducers which are added to water-based fluids. These friction reducing agents are typically latex copolymers of acrylamides. Examples include oil-soluble anionic liquid, cationic polyacrylate liquid, and cationic friction reducer [43].

Acid corrosion reducers. When acids are used in fracturing operations, corrosion inhibitors such acetone should be added to prevent corrosion of steel casings, tubing, and other equipment [43].

Viscosity stabilizers. Once the fracturing fluid with sufficient viscosity is prepared, additives are required to prevent the loss of viscosity at high reservoir temperatures [110]. Methanol and sodium thiosulfate are commonly used to stabilize the viscosity by acting as free radical scavengers in water-based fluids.

2.1.10. Proppants

Proppants are solid material mixed with fracturing fluid and pumped down the wellbore and into the hydraulic fractures to keep the fractures open during the fracturing operation as well as to prevent the complete closure of the fracture after the hydraulic pressure is removed during the flowback and further production from the reservoir formation [33, 111]. The most common proppants used in hydraulic fracturing include sand, manufactured ceramic material such as sintered bauxite, resin-coated ceramic, high-strength glass beads, aluminum alloys, steel shot, rounded nut shells, and plastic pellets [43, 112].

Grain diameter size of proppants is less than 1/16 inch and proppants with different sizes are available. In each hydraulic fracturing operation, a particular size of proppants or different sizes can be used with the smaller sizes intended for placement closer to the fracture tip. The main challenges regarding the use of proppants in hydraulic fracturing include [43]:

- Proper proppant placement
- Prevention of crushing or embedment
- Plugging at restrictions
- Potential flowback of proppants to the wellbore

The main purpose of using proppants is to provide the maximum permeability in the fracture to produce oil or gas from reservoir formations. Fracture permeability depends on grain roundness, purity, and crush strength of the proppants. The ideal proppant should result in the maximum fracture conductivity which is defined as the product of fracture width and permeability of the proppants. Common proppant permeabilities range from 100 to over 200 Darcies at no-stress conditions. At low closure stresses, larger proppants provide greater permeabilities, but the downside is their mechanical failure and crushing to fine particulate matter at high closure stress. Indeed, beyond a certain threshold stress, performance of smaller proppants in terms of providing permeability exceeds that of larger proppants.

Fracture conductivity is subject to change during the life of the well and may reduce due to [43]:

- Increased stress on proppants
- Reduced proppant strength due to corrosion
- Proppant crushing
- Proppant embedment into the formation
- Damage resulting from fluid-loss additives or gel residue

2.2. Reservoir Heterogeneity Impact on Hydraulic Fracturing Performance

Oil and gas operator companies can consider the development of tight gas sandstone reservoirs economically feasible only when well stimulation operations such as large hydraulic fracture treatments are planned. Hydraulic fracturing operation in tight reservoirs increases the connectivity of the well to more reservoir layers and further regions, thus boosting the production. However, the induced fracture is not the main reason for the success of many of the field developments in tight gas sandstone reservoirs.

Comparing the performance of different hydraulically fractured wells in SNS reservoirs, the more productive multiple hydraulically fractured horizontal wells (MHFHW), which far outperform other wells, are usually connected to high permeability streaks or natural fractures which constitute the two main elements of reservoir heterogeneity. Therefore, a practical integrated approach for modelling the high permeability streaks and natural fractures that are connected to hydraulic fractures is required for evaluation of the degree to which the hydraulic fracturing performance is impacted by reservoir heterogeneity [14, 113].

In the case of tight gas reservoir, hydraulic fracturing is an essential tool for obtaining an economical production rate. For optimising the process, different reservoir and geological issues must be considered. This may include understanding of main geological characteristics of the formation (depositional environment and tectonic activity), basic rock mechanics properties (e.g. stress regime, Young's modulus, and Poisson ratio), reservoir characteristics (permeability/porosity distribution and pressure), and well completion strategy [113].

It is difficult to evaluate the well performance of a multiple hydraulically fractured horizontal well without using a suitable inclusion of induced fractures in a reservoir simulation model. There are different approaches to evaluate the well performance of a hydraulically fractured well. Each approach has its own advantages and requires a different level of details for modelling. Accordingly, the prediction reliability depends on the methodology strength in capturing more of the contributing production mechanisms and the underlying physics [14].

The most common modelling approaches for incorporating the effects of hydraulic fracturing include negative well skin factor [114], course-grid transmissibility multiplier [115, 116], and Local Grid Refinement (LGR) transmissibility modification [117, 118]. The LGR method offers more modelling flexibility since 3D properties with higher resolution can be modelled to help incorporate the reservoir heterogeneity. Ideally, the fracture cell (i.e. the cell which hosts the induced fracture) should have similar width to the induced fracture which can be, for example, in the range of 0.03–0.51 in. (based on the data from 24 hydraulic fracture jobs performed in a Southern North Sea field). Using such small cell sizes violates one of the assumptions of well modelling in finite difference simulators (Peaceman radius formula) and adds error to the well performance calculations. It is also extremely slow and generates convergence problems in numerical reservoir simulations [118]. One solution is to consider thicker fracture cells and upscale the hydraulic fracture conductivity to the fracture cells.

In the presence of natural fractures in tight formations, the physics and modelling become more complicated and challenging. Due to difficulties of designing and performing experimental work on fracture network propagation in the laboratory settings and the difference of laboratory and reservoir scales, numerical modelling has become an essential tool in hydraulic fracture studies, as it facilitates incorporation of many details and conditions in modelling and prediction of fracture network geometries [119].

Some authors have attempted to simulate hydraulic fracturing in naturally fractured reservoirs considering the complexities involved. Fracture modelling approaches based on the Boundary Element System (BES) were applied by some researchers [120, 121, 122]. Zhao and Young [123] developed a dynamic 3D Distinct Element Model (DEM) based on tri-axial fracturing laboratory experiments to simulate fluid injection into a reservoir with natural fractures. Ben et al. [124] used Discontinuous Deformation Analysis (DDA) to simulate hydraulic fracturing.

Huang and Ghassemi [125] used the Virtual Multidimensional Internal Bonds (VMIB) evolution function for numerical simulation of 3D fracture propagation at micro scale. Using this method, they successfully represented the features of tensile and compressive fracture propagation and suggested that 3D simulation of fracture propagation helps understanding and designing multiple hydraulic fractures. Zhang et al. [126] used the lattice cell version of the discretized virtual internal bond method to model the reservoir rock for numerical simulation of the fracture development behaviour in complex unconventional reservoirs.

Hamidi and Mortazavi [127] simulated the hydraulic fracture initiation and propagation through intact rock using 3D Distinct Element Code (3DEC) and introducing a fictitious joint technique to facilitate importing the fracture initiation capability in the DEM approach. Zhang et al. [128] have given a full account of hydraulic fracturing simulation approaches and concluded that Displacement Discontinuity Models (DDM) can best simulate the complex fracture networks.

Considering the fact that most of the numerical fracture modelling approaches are mainly suitable for hard rocks due to assuming planar fracture geometry and linear plastic fracture mechanics, Wang [129] used Extended Finite Element Method (XFEM) together with Cohesive Zone Method (CZM) and Mohr-Coulomb theory of plasticity to investigate the initiation and development of non-planar fractures in brittle and ductile rocks. To address the same issues and investigate non-planar hydraulic fractures by 3D simulation, Sobhaniaragh et al. [130] also combined the Cohesive segments with Phantom Node Method and called it CPNM. Nadimi et al. [131] presented a new meshfree 3D simulation model based on Peridynamic (PD) method for investigation of hydraulic fracture development and geometry in complex and heterogeneous formations; the method also considers the interaction of the induced fractures with the natural fractures.

Despite their basic nature, coupling of these models with a commercial simulator for investigating the interaction of induced fractures with natural fractures is difficult and currently not fully practical. Therefore, on performance evaluation of hydraulic fractures, a methodology is required that can:

1. Serve as diagnostic tool to identify the heterogeneity in terms of natural fractures and/or high permeability streaks;
2. Support the tuned initial guess for connectivity calculation of upscaled fracture cells to reduce the associated uncertainty;
3. Link the findings to geological features.

These features have not been quantitatively integrated in the methodologies proposed by the investigators so far. In this thesis, it is suggested that such a technical gap can be filled through integration of well test results with fracturing operational data analysis for diagnosing and evaluating hydraulic fracturing performance. To link the hydraulic fracturing modelling with well test interpretation, a new methodology is proposed to quantify the heterogeneity impact on hydraulic fracture performance in terms of a new parameter defined as Heterogeneity Impact Factor (HIF). This parameter represents a quantified value for the expected performance of hydraulic fracturing on each well considering the contribution of heterogeneity. HIF creates a basis for comparing the wells of the same field with each other and also can exhibit the degree of heterogeneity in different fields.

Quantification of heterogeneity impact as a value is important as it can be used for prediction of well production by integrating the tools of production simulation with HIF. The results of the application of the proposed technique in one of the SNS reservoirs were in very good agreement with geological and drilling observations. The HIF analysis was then incorporated into the dynamic simulation model and pressure predictions of the model were compared with the three-week annual shut-down. The build-up response and its derivative displayed an excellent match which provides evidence of successful application of the proposed technique.

In the following chapters, first, a workflow is proposed to analyse the hydraulic fracture performance [2]. It is an integrated multi-disciplinary approach for deploying the data and information available all the way from seismic interpretation to reservoir dynamic modelling to evaluate the performance of the hydraulic fracturing. Upon the foundation of the hydraulic fracture performance analysis workflow, the newly proposed HIF analysis is built for evaluating the performance of fracked wells as well as to show the impact of reservoir heterogeneity. HIF analysis is then applied to the real field data.

It is worth mentioning that the methodology in this study is, indeed, focused on combining the results of well test analysis (where the production-pressure is matched) with the results of net-pressure match (where pressure depletion is characterized and matched using specific parameters). Once these two matches are obtained, since well test considers a larger radius of investigation and net-pressure considers a smaller radius of investigation, the relation between them can be used to conclude a zero-dimension property of the reservoir heterogeneity which we have quantified and defined as HIF. Finally, the results of the work are compared with geological evidences and validated by matching the pressure predictions of the resulting dynamic reservoir model with the real well test data.

2.3. Production Forecasting for Hydraulically Fractured Wells in Heterogeneous Reservoirs

As the industrial investments in developing lower permeability reservoirs increase and more advanced technologies, such as horizontal drilling and hydraulic fracturing, gain more attention and applicability, the need for more reliable means of production forecasting also become more noticeable. Production forecasting of hydraulically fractured wells is challenging, particularly for heterogeneous reservoirs, where the rock properties vary dramatically over short distances, significantly affecting the performance of the wells. Despite the recent improvements in well performance prediction, the issue of heterogeneity and its effects on well performance have not been thoroughly addressed by the researchers and many aspects of heterogeneity should still be explored [1].

Because the experimental investigation on the efficiency and feasibility of well production is tedious, expensive, and, in some cases, unsuccessful in finding reliable results, different methodologies for forecasting production wells have been developed and published. On the basis of empirical relationships of the production rate versus time, Arps [132] introduced the decline curve analysis (DCA) method, which was later augmented with type curves by Fetkovich [133]. This method, which consists of the exponential, hyperbolic, and harmonic models, has been further improved [134, 135, 136, 137, 138, 139, 140] and frequently used in the industry for a long time.

Several authors investigated the performance prediction of horizontal wells for different flow models [141, 142, 143, 144, 145, 146, 147]. Other authors modified the vertical well fracture performance models to be used for horizontal wells [148, 149]. However, because most of the homogeneous and giant hydrocarbon reservoirs have been developed and produced over the last century, development of more heterogeneous and challenging oil and gas fields has become the new trend for the industry. This needs advanced approaches for capturing further complexities in production forecasting, which serves as the foundation for field development decision making [2].

Heterogeneity has been a serious challenge for production forecasting because it dramatically affects the productivity of wells and jeopardizes the development plan. This problem may deteriorate the economics of tight reservoir development because expensive stimulations strain the benefit margins. Modeling such stimulations and more reliable forecasting will lead to better understanding of the project outcomes. By virtue of information technology (IT) advancement, some numerical models have been developed

[150, 151, 152], but they are highly time consuming to use and require a great deal of inputs.

Recently, some authors have worked on forecasting the production from fractured wells. Hwang et al. [153] introduced a method that addresses the problem of having natural fractures, which is only one element of heterogeneity, by considering the fractures as a combined series of slab sources and superposing the sources under several boundary or flow conditions. They suggested that, to reflect the heterogeneous nature of natural fractures, a stochastic method of generating discrete fracture networks should be adopted. The challenge, therefore, lies in data gathering and modeling the natural fractures. These authors suggested the fractal discrete fracture network (FDFN) model, which incorporates the various scale-dependent data, such as outcrops, logs, and cores, and creates more realistic natural fracture networks. This FDFN model is combined with the slab source model to build fracture networks first, and then the flow problem in the complex fracture systems is solved [153]. However, the choice by Hwang el al. of discarding other sources of heterogeneity to avoid further complications in forecasting leaves their work incapable of thoroughly addressing the effect of heterogeneity on well production performance.

Weng [154] presented a comprehensive overview on modeling hydraulic fractures covering natural fracture impact and revealed the fact that precise prediction of detailed fracture geometry is still very challenging. He also concluded that, even though many modeling approaches have been explored and models are developed to simulate complex fractures in the naturally fractured reservoir, most have some limitations, have limited focus, or lack full functionalities to simulate the entire fracturing process. In parallel, MoradiDowlatabad and Jamiolahmady [155] developed a new equation that can predict multi-fractured horizontal wells performance under pseudosteadystate flow conditions in tight reservoirs. Holey and Ozkan [156] presented a theoretically rigorous approach based on an anomalous diffusion model for the performance of fractured horizontal wells surrounded by a stimulated reservoir volume. The latter two methods, however, have not considered the impact of heterogeneity in the form of natural fractures. Thus, an empirical approach can provide a primary means for screening purposes or a secondary truth-checking controller.

In this thesis, a novel methodology called DCH is introduced for considering the heterogeneity impact on well production forecasting based on decline curve analysis. The method is empirical and applicable to multi-fractured horizontal wells in formations with permeabilities of less than 0.1 millidarcy (mD). This approach relies on HIF to link the hydraulic fracturing and modeling with well test interpretation by quantifying the heterogeneity impact on hydraulic fracture performance. Successful application of the proposed DCH approach is validated against data from a Southern North Sea field using the most detailed three-dimensional (3D) history matched reservoir simulation model.

2.4. Economic Evaluation of Hydraulic Fracturing Operations

Although the fracturing technique is now considered an essential part of the reservoir management backbone in tight/shale gas field developments, the complexities associated with the hydraulic fracturing dictate some degree of uncertainty in successful economic applications [157, 158, 159, 160]. Some prominent characteristics of these reservoirs, such as very low permeability and high initial gas flow rate followed by a sharp decline, cause the economic evaluation of the process to be usually accompanied with significant difficulties. Quantification and understanding the associated risk and uncertainty provides grounds for determining whether a particular hydraulic fracturing job can be commercially feasible or not [161, 162, 163, 164].

The chance of achieving commercial production is the main uncertainty in development of unconventional play. In this regard, Harding [165] argued that a deterministic solution cannot account for the uncertainty of input assumptions. He presented a stochastic approach to evaluate several commercial realizations in which the risk of failure and uncertainty of success for different stages of the process was calculated. There have also been suggestions on a stochastic approach based on multi-disciplinary participation and iterative modeling in unconventional project evaluation [166].

Williams-Kovacs and Clarkson developed tools that incorporate pre-drill screening, exploration, pilot, and commercial demonstration to quantify the risk and uncertainty in shale gas prospecting and development. This method employs production data analysis and forecasting approaches to compare shale gas prospects in a stochastic manner [167].

More recently, Liang et al. [168] proposed a workflow in which an in-house uncertainty quantification package is coupled with hydraulic fracturing modeling and reservoir simulation. In this process, several parameters including permeability of the matrix, completion information, and fracture properties were incorporated. The proposed methodology utilized a top-down concept and can proceed the model from a big 3D model to pad-scale and single well models. This integrated approached has been applied to an unconventional reservoir factory-model development in the Permian Basin.

As can be inferred from the literature, despite the considerable number of fracking projects applied, relatively limited approaches are available in modeling and quantifying uncertainty and risk in successful application of massive hydraulic fracturing techniques. However, numerous investigations on uncertainty/risk analysis and optimization in reservoir simulation jobs have been reported. Therefore, from the decision-making point of view, a logical way to evaluate an unconventional asset can be achieved through incorporation of some characteristic features into these models.

Among different approaches in this area, Thiele and Batycky [169] have recently introduced a new methodology, called EVOLVE, to quantify the reservoir uncertainty. This linear workflow is comprised of four key stages from screening and model selection to Net Present Value (NPV) calculation. In this work, streamline class of simulators were used due to their unique feature of capturing injector-producer connectivity [170, 171, 172]. As a main characteristic, EVOLVE deploys a distance-based generalizes sensitivity. They suggested that this was a unique and powerful workflow that covers different aspects from geological and simulation parameters and forecast scenarios to economic evaluation [169]. Although this approach and the others which fall in such a category can result in a detailed characterization of different aspects of the reservoir, they would be extremely tedious and time consuming in case of heterogeneous reservoirs.

There are other parameters that can be potentially incorporated into the sensitivity workflow, such as impact of geomechanically induced heterogeneity (porosity, permeability, and net-to-gross) in the reservoir either analytically [173] or numerically on reservoir scale [170]. Since heterogeneity is one of the main concerns in evaluating a hydraulic fracturing job in an unconventional gas reservoir, seeking a new quick method to account for the heterogeneity impact seems inevitable.

In this thesis, based on the HIF and DCH approaches developed prior to the economic evaluation stage, a highly time-efficient workflow is proposed from which the Risk of Commercial Failure (CCF) due to the impact of reservoir heterogeneity can be evaluated. To achieve this, our suggested gas flow model (decline curve using heterogeneity impact factor, DCH) was incorporated in an economic evaluation platform from which NPV of a hydraulic fracturing job could be calculated for a range of realizations. The sensitivity analysis included the reservoir heterogeneity in terms of Heterogeneity Impact Factor (HIF) as the main influencing parameter. In addition, the sensitivity of the other parameters such as Capital Expenditure (CAPEX), Operational Expenditure (OPEX), gas price, and discount rate to NPV was also reported. The output of the proposed approach was the computation of RCF.

Chapter 3. Methodology

3.1. Heterogeneity Impact Factor (HIF)

Modelling hydraulic fracturing net pressure provides hydraulic fracture dimensions and connectivity per fracture job. Moreover, well test interpretation can imply the active number of hydraulic fractures and an average estimation of their dimensions and connectivity after cleaning up and flowing the well. There is a technical gap in the integration of well test data with fraccing operational data for diagnosing and evaluating the hydraulic fracture performance. In this section, we develop a novel approach to link the hydraulic fracturing modelling with well test interpretation. This method quantifies heterogeneity impact on hydraulic fracture performance through defining a new parameter called Heterogeneity Impact Factor (HIF).

3.1.1. Hydraulic Fracturing Modelling Workflow

There has been a lack of research on the integrated aspects of the hydraulic fracturing in terms of the essential work required from the geologist, geophysicist, petrophysicist, reservoir engineer and hydraulic fracturing engineer. A complete picture of the hydraulic fracturing modelling workflow requires an integrated multidisciplinary approach to be undertaken. A systematic workflow is hence proposed here (as illustrated in Figure 8) based on the logical link and knowledge sharing expected between different disciplines involved in planning, design, and implementation of hydraulic fracturing.

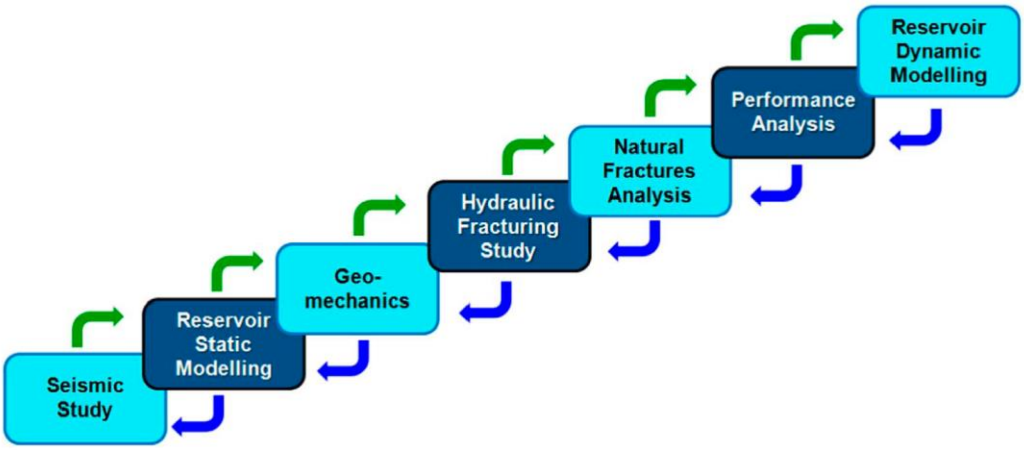

Figure 8. Integrated hydraulic fracturing modelling workflow

The integrated workflow suggested in Figure 8 includes the following elements and the disciplines involved:

1. Seismic modelling for structural uncertainty and seismic inversion (geophysics and geology)
2. Reservoir static modelling which requires:
    a. Knowledge of the intrinsic permeability and porosity of the reservoir (geology, reservoir engineering, and petrophysics)
    b. Knowledge of the capillary pressure (P_c) and water saturation (S_w) in the reservoir (reservoir engineering and petrophysics)
    c. knowledge of the free water level (FWL) and its associated uncertainty (reservoir engineering, petrophysics, and geology)
3. Incorporating the geomechanics into the model using stress modelling and knowledge of the geomechanical stresses and their directions in the reservoir (geomechanics, petrophysics, hydraulic fracture engineering)
4. Study of hydraulic fracturing process to anticipate the potential effects on the reservoir and performance of hydraulic fractures (hydraulic fracture engineering, reservoir engineering)

5. Analysis of the hydraulic fracture propagation via net pressure matching and G- function analysis (hydraulic fracture engineering, reservoir engineering)

6. Analysis of the hydraulic fracture performance via Production Logging Tool (PLT) data and well test analysis (hydraulic fracture engineering, geology, reservoir engineering)

7. Analysis of the existence of natural fractures or high-permeability streaks in the reservoir (reservoir engineering, geophysics, and geology)

8. Modelling of the hydraulic fracture in a dynamic reservoir model (reservoir engineering)

9. Cross-checking the results of dynamic model against every component of the workflow to ensure a coherent understanding of the reservoir.

The elements of the above workflow and their expected outcomes are explained in detail throughout the following sections.

A. Seismic Study

In addition to standard seismic interpretation workflows, seismic data can be used to obtain the natural fracture information as below:

1. Describing the faulting and structural shape on a kilometer scale by structural interpretation of seismic data.

2. Gaining insight into fractured or under stress zones by inverting the pre-stack seismic data to elastic properties such as shear impedance and acoustic impedance and calculating elastic properties of rocks like Poisson’s ratio, Young’s modulus, brittleness index, etc.

3. Azimuthal analysis of seismic data to describe fractures in the range of 10 meters. Amplitude variation with azimuth (AVAZ) and simultaneous

inversion of azimuthal angle stack seismic data are the methods used. Azimuth and offset distribution of the seismic data must be wide and dense to be able to obtain an accurate azimuthal anisotropy.

A feasibility study determines which method can be utilized for seismic inversion or azimuthal studies. If seismic inversion analysis is available (e.g. acoustic impedance for a targeted sand interval in time), then an integrated multi-disciplinary team may observe cross-sections of the areas where there are higher uncertainties and concerns rather than relying only on 2D maps. Some typical quality checks include:

a. Quality maps for seismic data including possible noise, possible non-geological amplitude variations, etc.

b. Well to seismic tie and wavelet estimation quality; this adds uncertainty and also quality of the well logs used for inversion should be re-visited.

c. Map of seismic to inversion synthetic correlation for target interval which shows how much uncertainty one can expect.

d. Map of the signal to noise ratio for the target interval

e. Cross plot and correlation of porosity from the neutron log (NPHI) to inversion results at the target interval in seismic data resolution; this adds another uncertainty for estimating porosity.

f. Overlaying the PLT of the previous fracked wells on the results of seismic inversion to validate the results or obtain possible explanations

B. Reservoir Static Modelling

It is essential to understand the inherent nature of the tight gas sandstone reservoir in the SNS region. Sandstones deposited by aeolian and fluvial processes interdigitating with sabkha and playa lake siltstones and minor shale deposits introduces a varied facies distribution in the reservoir model that needs to be well-understood with the help of core logs, regional geological studies and analogues. In the SNS tight gas sandstone reservoirs, the entire reservoir section may be filled with pervasive authigenic illite due to the late gas charge in these reservoirs and prolonged residence in the illite generating window. The illite is of the flaky and fibrous variety, which forms honeycomb and mat-like structures in the pore spaces and has a detrimental effect on permeability. Air permeability typically ranges from 0.1 – 1mD.

Porosity and permeability modeling. In addition to the detrimental effect of illite on permeability, overburden stress also reduces permeability and porosity due to the decrease in size of the thin, tabular pore throats that connect the larger pores. Gas effective permeability at irreducible water saturations is also another factor that further reduces permeability due to the interference of gas and water flow within common flow channels. Overall, when compared to air permeability from core, up to 2 orders of magnitude in permeability reduction can be expected in the SNS tight gas sandstone reservoirs.

In order to model the permeability reduction, the facies of the reservoir should be defined and based on SCAL results, the overburden stress corrections can be applied. The gas effective permeability can be modelled using a correlation based on the combination of the relative-permeability laboratory results and Keelan's method [174]. Furthermore, the trapped gas saturation should be defined from analogue fields or from laboratory results if they are available. The resulting permeability model is compared to the results of PLT and well tests by reconstructing the cumulative permeability-height (KH) log using the steps shown in Figure 9.

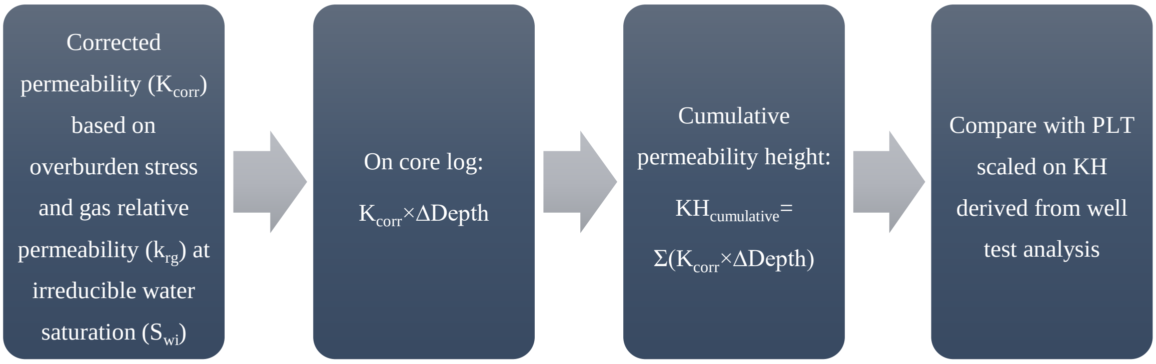

Figure 9. Workflow of comparing KH based on corrected permeability with well test derived KH

The overall permeability modelling workflow is summarized in Figure 10.

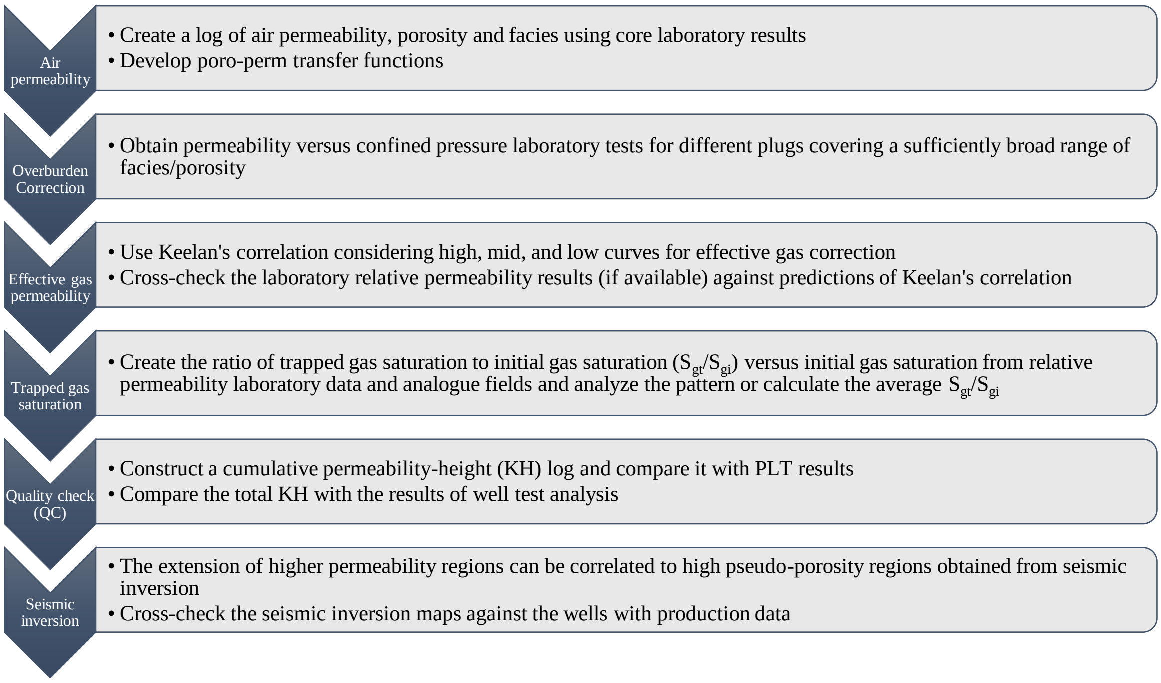

Figure 10. Permeability modelling workflow

Capillary pressure and water saturation modeling. Initialization of the simulation model provides the initial conditions that define the fluids initially in place and initial reservoir pressure. There are several ways to perform the simulation model initialization to match the initial water saturation with the log-derived water saturations. However, due to the nature of tight gas sandstone reservoirs, initialization based on capillary pressure curves is preferred in this study. The workflow of P_c and S_w modeling is detailed below in Figure 11.

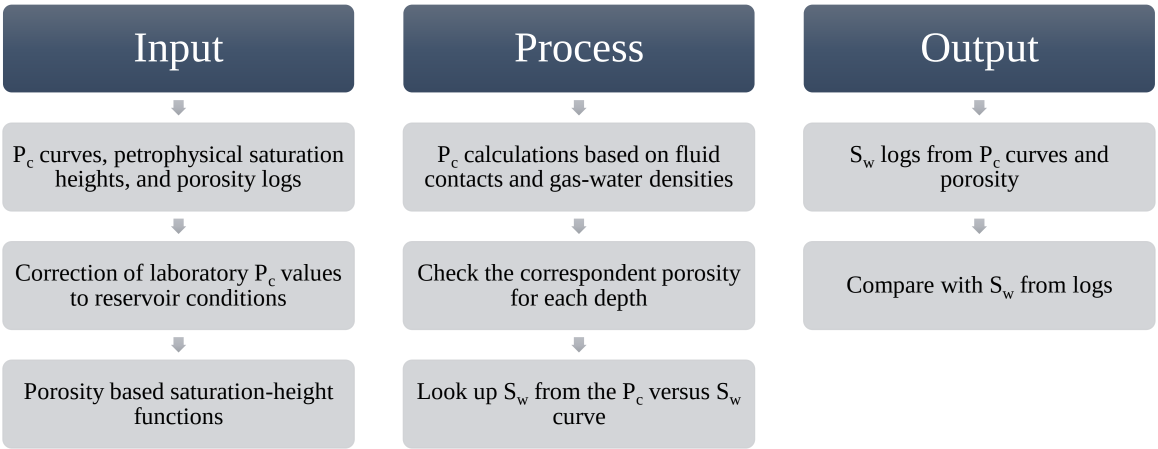

Figure 11. Capillary pressure and water saturation modelling workflow

In order to obtain a match with the log-derived water saturations, capillary pressure curves have to be derived for each rock type. The rock type is defined based on a porosity binning system. If there is insufficient laboratory data available, a porosity-based modified lambda function can also be used. This can then be compared with the log-derived water saturation.

Free water level uncertainty. It is common to find that in the SNS tight gas sandstone reservoirs, the FWL may not be penetrated or observed. FWL from analogue fields can be used to narrow the uncertainty and saturation height models can also be used. However, due to the tight nature in these low-permeability reservoirs, simple saturation height models like Leverett J-Function do not work well as these models rely on a porosity-permeability relationship which is poorly defined in these reservoirs. The Thomeer model, however, proves to be a better match to the log-derived water saturations and may better define the FWL. It is important to cross-check the water saturations created with the saturation height models with log-derived water saturations.

C. Geomechanics Study

The study of the rock stresses and directions is perhaps one of the most critical requirements for hydraulic fracturing. It provides vital information on the force required to break open the rocks, the direction of fracture propagation, and how we can design a hydraulic fracture to maximize its production potential.

Geomechanical stresses and their directions in the reservoir. Rock mechanics tests on core samples of the discovery and appraisal wells should be performed for Young's modulus and Poisson ratios, Uniaxial Compressive Strength (UCS) and Uniaxial Tensile Strength (UTS), and the determination of in-situ stresses magnitudes and directions. This information should give an indication of the average field stresses. However, the field stresses need to be cross-checked with the analysis of borehole image logs available when drilling the development wells. It has been observed that variations in local stresses can result in differences in the maximum horizontal stress directions. This would determine if a longitudinal or transverse fracture would be created during the hydraulic fracturing process. Based on available literature [175], any deviation greater than 15° from the maximum horizontal stress would lead to a transverse fracture being formed during the hydraulic fracturing process.

1-D Stress Modelling. Based on the core laboratory results for the appraisal or discovery wells, correlations can be made between the density or gamma ray logs with the stress in reservoir layers. With the use of the reservoir static model, an estimate of the stress profile across a fracture initiation point can be created facilitating a frac design. The actual stress where the fracture initiation point occurs can be obtained from the mini-frac data, hence the stress data in the other layers can be calibrated.

D. Hydraulic Fracturing Study

It is important that we understand the hydraulic fracturing design program and process as it affects the way the hydraulic fractures are created in the reservoir. We can break down the complexity of the factors that influence the propagation of a hydraulic fracture from a reservoir perspective as illustrated in Figure 12:

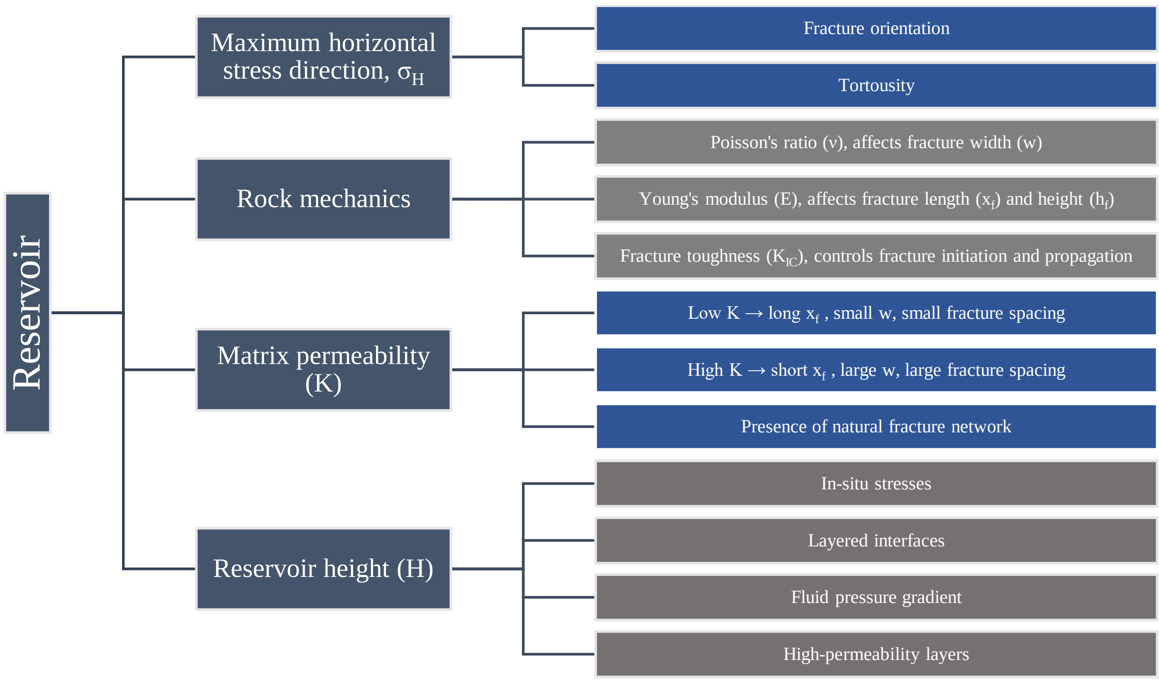

Figure 12. Factors influencing the hydraulic fracture propagation process

The factors that influence the hydraulic fracture propagation introduced in the above figure include:

- **Maximum horizontal stress (σ_H) direction** will allow us to estimate the fracture orientation as hydraulic fractures tend to propagate along σ_H. Deviating from σ_H introduces tortuosity into the hydraulic fracture propagation process and requires more energy to propagate the hydraulic fracture further into the reservoir.
- **Rock mechanics data** such as Poisson's ratio, Young's modulus and fracture toughness allows us to estimate the fracture width, fracture length, fracture height and the energy required for fracture initiation and propagation.
- **Matrix permeability** has a considerable influence on the optimum type of hydraulic fracture design. In a low permeability environment, the optimum design tends towards longer fracture half-length, smaller fracture width and spacing, whereas the opposite is true for high

permeability environments. With the presence of natural fracture networks, a hydraulic fracture that penetrates the network would access a larger drainage area.

- **Reservoir height** has a profound influence on the hydraulic fracture height propagation. The in-situ stresses would dictate how high the fracture can grow and if layered interfaces of great stress differences exist, they may lead to the branching of the fractures. If high-permeability layers exist, they also tend to influence the fracture growth as a high leak-off rate will be experienced.

In addition to the reservoir factors that influence the hydraulic fracture propagation process, operational factors such as perforation strategy can also play a big role in the propagation process. The orientation of the perforation has little influence on the orientation of the hydraulic fractures. However, the misalignment from maximum horizontal stress can lead to higher breakdown pressures. It is known that local stress regimes can differ quite greatly in the SNS tight gas reservoirs. Therefore, it is advisable that a 60° perforation phasing is used instead of a 180° phasing in order to reduce the chance of misalignment from the maximum horizontal stress.

Moreover, the perforation interval is also extremely important in the fracture initiation and propagation process. Based on laboratory studies and field experience [175], a short perforation interval allows for more pressure to be directed to fracture propagation whereas a large perforation interval leads to the creation of multiple fractures instead of a focused bi-wing hydraulic fracture that is designed.

E. Fracture Analysis

It is important to re-investigate the hydraulic fracture post-job data in order to identify the clues that can provide extra understanding of the performance of the hydraulic fractures.

Mini-frac analysis using G-function. In addition to fracture property estimation, the Nolte G-function can be used for qualitative detection of natural fractures in the formation. A plot of net pressure versus pressure decline function, G_p, must ideally result in a straight line. When the fracture closes, a deviation from the straight line will occur. If closure time equals the pump time, the G-function G(dt)=1. A value less than 1 indicates low fluid efficiency. High leak-off can also be detected during the pumping job when a sharp dive in net pressure is observed, indicating that the fracking fluid is being leaked off into the formation instead of propagating the fracture.

Hydraulic fracture propagation and net pressure matching. Based on net pressure matching, an estimate of the fracture half-length x_f, fracture height h_f, fracture width w_f, and its conductivity F_{cD} can be obtained. In a hydraulic fracturing job, the injection parameters (i.e. surface pressure, bottomhole pressure, flow rate, fluid volumes, proppant concentration) were recorded in real-time and this is fed into a hydraulic fracture modelling software. The software utilises the closure stress profile, rock mechanical properties from the static model to match the net pressure obtained from the injection parameters and leak-off behaviour. Based on the net pressure match, an estimate of the fracture geometry and conductivity can then be obtained. Note that the net pressure match is non-unique, hence, it needs to be calibrated for example using well test analysis results.

Evidence of natural fractures and high-permeability streaks while drilling. In addition to the low fluid efficiency observed in the G-function analysis, static mud losses observed while drilling can be clues to the existence of natural fractures or high-permeability streaks. With the analysis of density image logs, mud losses may coincide with the presence of a cluster of low-density features. An example is shown in Figure 13.

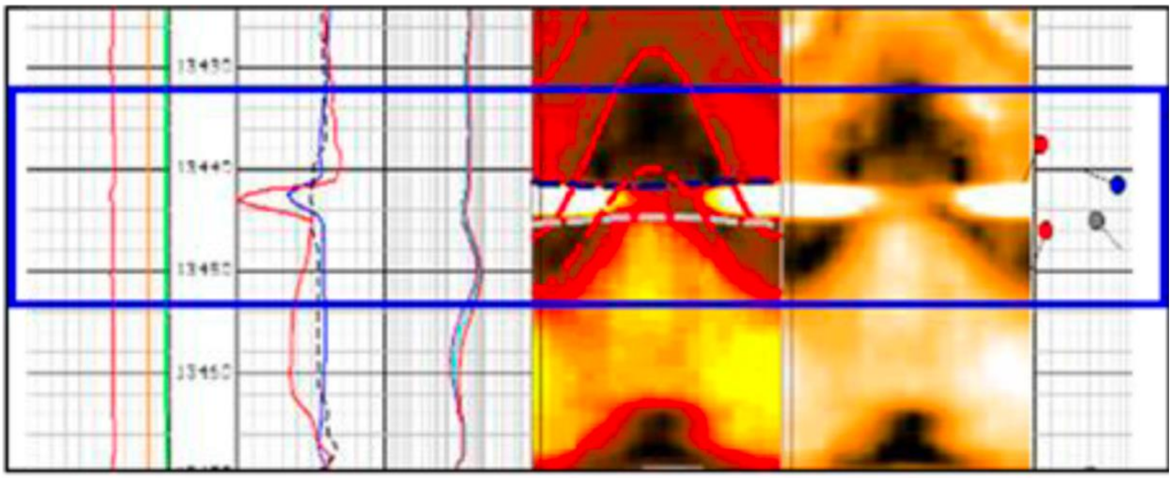

Figure 13. Density image logs show potentially open fractures in the same regions where drilling mud losses occurred.

Analysis of closure pressure and proppant compressive strength. Proppants in hydraulic fractures are held under stress due to the closure pressure exerted by the rocks, offset by the pore pressure in the fracture. When the effective stress (the difference between closure pressure and pore pressure in fractures) exceeds the compressive strength of the proppant, proppant shear failure occurs. When the reservoir is being depleted the effective stress increases due to reduction of pore pressure. This can lead to the closure of the hydraulic fracture and hence a productivity decrease would be expected. A simplified method can be used to estimate when this will happen.

In order to calculate the proppant failure criteria, the initial closure pressure has to be known via the mini-frac analysis and the compressive strength of the proppant used in the hydraulic fracture has to be measured in the laboratory. The tensile strength can be estimated to be 1/20 of the compressive strength. With this information, the effective stress is simply the difference between the closure pressure and the pore pressure, while the compressive strength of the fracture is the summation of the pressure in the hydraulic fracture and the tensile strength. A summary diagram for calculation of proppant failure criteria is shown in Figure 14.

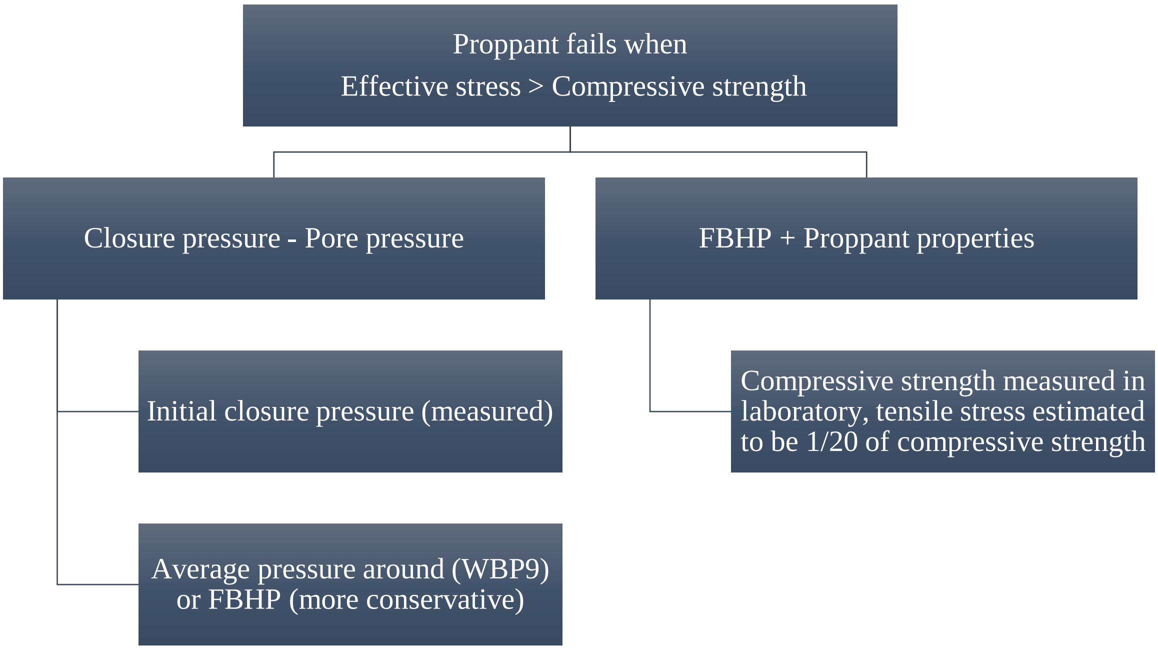

Figure 14. Calculation of proppant failure criteria

F. Fracture Performance Analysis

The fracture performance can be analysed by several methods including PLT, well tests, tracers, and microseismic. It is very important to note that these methods should be linked to the reservoir geology.

Analysis of hydraulic fracture performance with PLT. Based on the PLT results, it is usually believed that a hydraulic fracture with higher proppant concentration should perform better. However, it may be difficult to find a correlation between hydraulic fracture geometry, its proppant coverage and their production performance [176]. However, the productivity of each fracture can be obtained from the PLT and this can be history-matched in the dynamic model.

Estimating fracture characteristics with well test analysis. Well test analysis can give an estimate of the number of active hydraulic fractures, their average fracture geometry (i.e. fracture height and half-length) and their average conductivities. In order to compare the results from the net pressure match and well test Pressure Transient Analysis (PTA), a WTA/Net Pressure Match ratio can be created. This ratio is the comparison of the product of fracture surface area ($x_f.h_f$) and fracture conductivity (k_{fw}) between the results derived from well test analysis and net pressure matching. It is then used to adjust the fracture conductivity in the LGR of dynamic simulation model using the workflow shown in Figure 15.

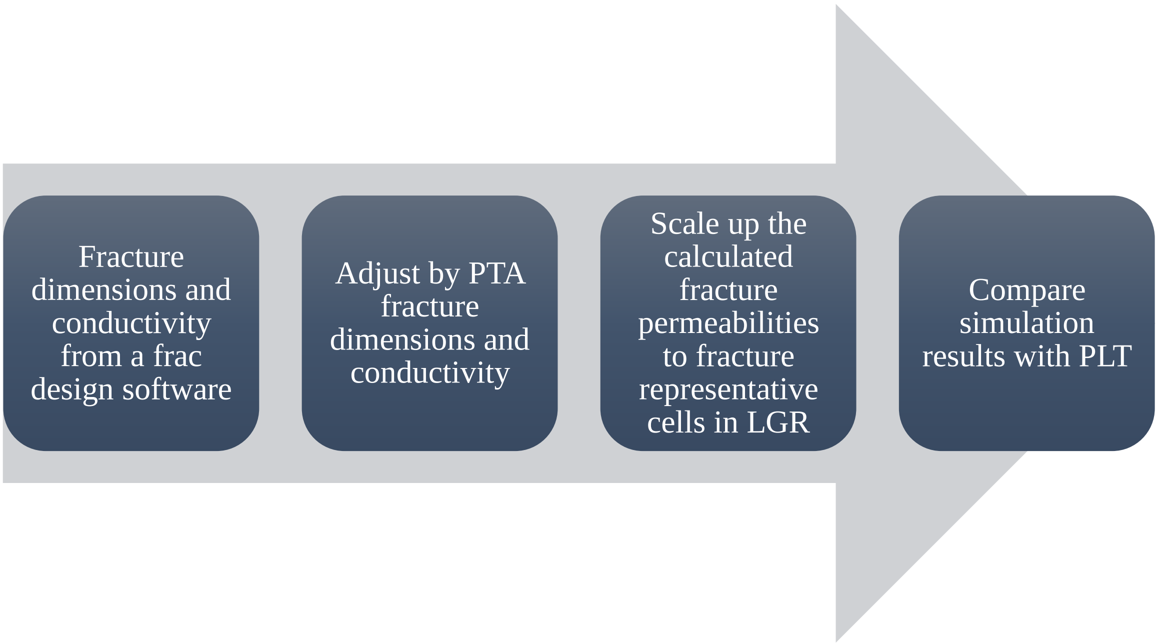

Figure 15. Workflow of initial fracture cell permeability calculation in LGR grids

There are three analytical well test models describing fluid flow and pressure behaviour of hydraulic fractures:

1. Infinite conductivity hydraulic fractures
2. Uniform flux hydraulic fractures
3. Finite conductivity hydraulic fractures

In infinite conductivity hydraulic fractures, it is assumed that pressure drop along the fracture is negligible, therefore fracture linear or bilinear flows are not practically observed. On logarithmic plot, the formation linear flow is seen with a slope of 0.5 followed by a pseudo-radial flow, for which the derivative becomes horizontal.

Flow in uniform flux hydraulic fractures behaves very similarly to infinite conductivity fractures, except that it is assumed that flow is uniform along the fracture length. Again, formation linear flow and pseudo-radial flow regimes can be observed if flow duration is long enough.

There is a considerable pressure drop along the finite conductivity hydraulic fractures. Therefore, bilinear flow (fracture linear flow and formation linear flow) occurs at early times. Bilinear flow is observed with the slope of 0.25 on pressure derivate plot. Then linear formation flow may or may not be seen because its duration is very short. Finally, pseudo-radial flow is developed.

Table 3 summarizes well test analysis methods for characterization of hydraulically fractured wells.

Table 3. Summary of PTA methods for hydraulic fractured wells

Flow regime	Plot specification	Analysis results
Linear flow	$\psi(P_{wf})$ vs. $\Delta t^{0.5}$	x_f
Bilinear flow	$\psi(P_{wf})$ vs. $\Delta t^{0.25}$	F_c
Linear and radial flows	$\mathrm{Log}[\Delta\psi(P_{wf})]$ vs. $\mathrm{Log}[\Delta t]$	$x_f.\sqrt{k}$, x_f, k, S
Bilinear and radial flows	$\mathrm{Log}[\Delta\psi(P_{wf})]$ vs. $\mathrm{Log}[\Delta t]$	F_c, x_f, k, S

G. Reservoir Dynamic Modeling

By integrating the findings from the reservoir characteristics, fracture characteristics and dynamic data observations, the reservoir dynamic model can be created. There are several different approaches available for hydraulic fracturing modelling within the reservoir engineering context. Understanding the key elements for fracture evaluation and considering those elements in dynamic model has an essential role for reliable forecasts. One of these elements is the fracture conductivity behaviour as a function of effective stress.

Accounting for decreasing fracture conductivity as the reservoir depletes. Conductivity of the fracture will be reduced during the life of the well because of the increasing stress on the propping agents. The effective stress on the propping agent is the difference between the in-situ stress and the flowing pressure in the fracture. As the well is producing, the effective stress on the propping agent will normally increase because the flowing bottom hole pressure is decreasing. Parvizi et al. [113] explained the workflow of integration of this mechanism in the dynamic model. This effect is normally measured in the laboratory by measuring fracture conductivity with increasing/decreasing proppant stress. The results can be translated into the dynamic model via the form of a fracture transmissibility multiplier versus pressure table. Grid cells that represent the fracture in the model can then be assigned the fracture transmissibility multiplier versus pressure table that was created.

Modelling hydraulic fractures using LGRs for covering complex production mechanisms. For more complicated issues such as water production of each fracture, evaluation of reperforation scenarios, and detailed analysis of build up pressure, LGRs can be created in the dynamic model to represent the fracture cells as shown in Figure 16. Using LGR cells to represent the hydraulic fractures, the fracture height, half-length and their conductivity can be defined individually. This allows for greater control of detail for history-matching purposes.

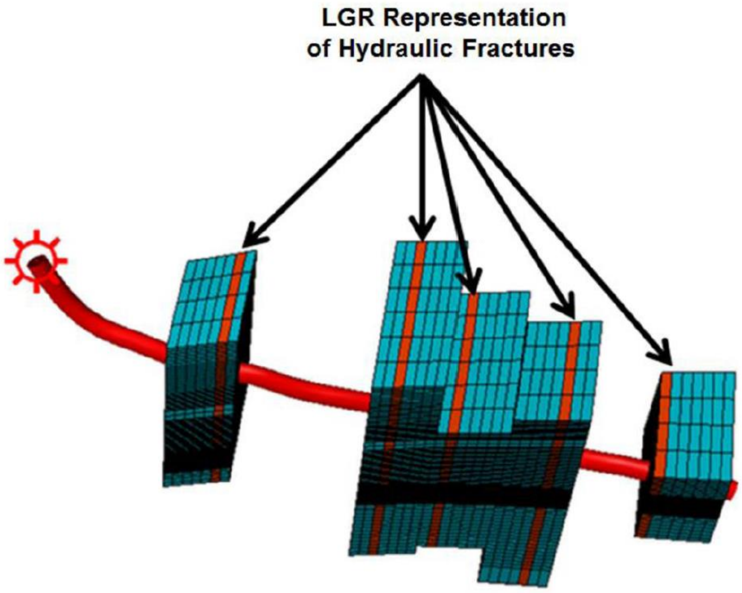

Figure 16. Example of LGR gridding for modeling hydraulic fractures

Assigning fracture height, half-length and permeability values to hydraulic fracture cells may not be straightforward in commercial software. For the purpose of history matching, the fracture height, half-length and permeability values need to be varied to achieve the best possible match. Automated workflows to vary fracture dimensions and properties can be created to aid this process. Historical production and pressure data should be used to modify the reservoir properties to match production performance. It is critical to consult geology and geophysics teams if any geological features such as fault transmissibility, pore volume multipliers and transmissibility multipliers are used.

3.1.2. Calculation of HIF

The hydraulic fracturing modelling workflow proposed in the previous section ends in creating 3D static and dynamic models. Some of the fundamental inputs to the workflow of hydraulic fracture performance evaluation are:

1. Results of net pressure match

2. Well test interpretations (pressure transient analysis)
3. PLT outcomes (production-data analyses)
4. Hydraulic fracture conductivity versus effective stress

A. Net Pressure Analysis

The difference between the pressure in the fracture and the in-situ stress (P_f – in-situ stress) is referred to as the net pressure. To estimate the patterns of growth for fractures in the field or after the treatment, the behaviour of net-pressure was defined by Nolte and Smith. In their analysis method, they used the model proposed by Perkins and Kern [177] and later modified by Nordgren [178] and hence called Perkins-Kern-Nordgren (PKN) theory. Based on the assumptions of the PKN theory, as long as the fracture height is contained, the net pressure will increase with time according to the following proportionality:

$$P_n \propto \Delta t^e$$

Where P_n is critical net pressure and Δt is change in time with $0.125 < e < 0.20$, and, slope, e= 0.20 for low leak-off and 0.125 for high leak-off. Leak-off is a measure of the fracture fluid-loss when the pumping stops.

Figure 17 is generated based on net pressure formulas Nolte and Smith defined. This Figure shows the relationship between net pressure and the rest of measurements during fracturing operation. Fracture geometry is inferred from net pressure and leak-off behaviour in this indirect diagnostic technique. The results of net-pressure match interpretations are not unique so careful application is required. This technique is most useful when results are integrated or calibrated with results of other diagnostics.

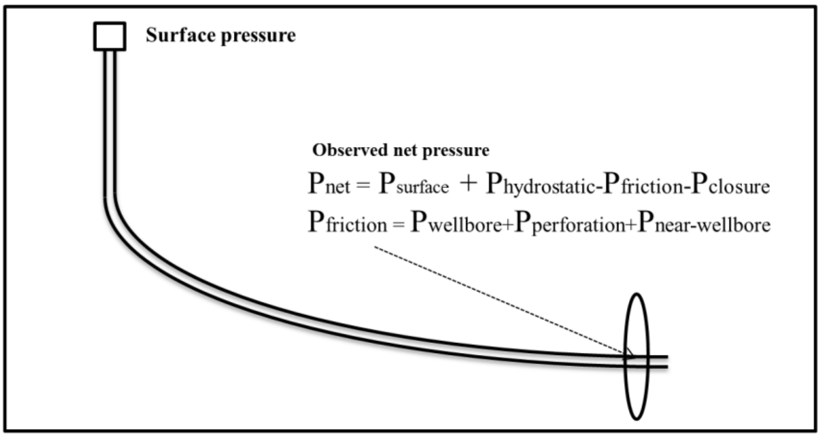

Figure 17. Net pressure calculation diagram

In a hydraulic fracturing job, the injection parameters (i.e. surface pressure, bottomhole pressure, flow rate, fluid volumes, and proppant concentration) are recorded in real-time and fed into hydraulic fracture modelling software. The software utilizes the closure stress profile and rock mechanical properties from the static model to match the net pressure obtained from the injection parameters and leak-off behaviour.

Through net pressure matching, an estimate of the fracture half-length x_f, fracture height h_f, fracture width w_f and its conductivity C_{fD} was achieved for the number of fracture jobs implemented in this field (Table 4).

B. Well Test (Pressure Transient) Analysis

It is possible to estimate of the number of active hydraulic fractures, their average fracture geometry (fracture height and half-length) and their average conductivity using well test analysis. Clarkson [179] described very detailed and comprehensive approach of production data analysis including well test interpretation for unconventional resources. During the well test matching process of the five multi-staged fractured horizontal wells, finite conductivity hydraulic fractures was assumed. This is because of uniform flux and infinite conductivity fracture assumption lead to a different pattern of pressure behaviour comparing with the real data.

C. Production Data Analysis

Productivity of each fracture may be obtained from PLT analysis and deployed to validate the expected flow contribution from net-pressure analysis, to check the number of active fractures obtained from well test interpretation and to tune the dynamic model. It is commonly believed that a hydraulic fracture with higher proppant concentration should perform better. However, due to heterogeneity it may be difficult to find a correlation between hydraulic fracture geometry, its proppant coverage and production performance. Therefore, PLT has a key role for understanding the effect of heterogeneity on the fracture performance.

D. Hydraulic Fracture Conductivity versus Effective Stress

Conductivity of the fracture will be reduced during the life of the well because of increasing stress on the propping agents. This effect is measured in the laboratory by measuring the fracture conductivity with increasing effective stress on proppants and the conductivity versus effective stress is obtained (Figure 18-a). The results are then translated into the dynamic model in the form of a fracture transmissibility multiplier versus pressure table (Figure 18-b).

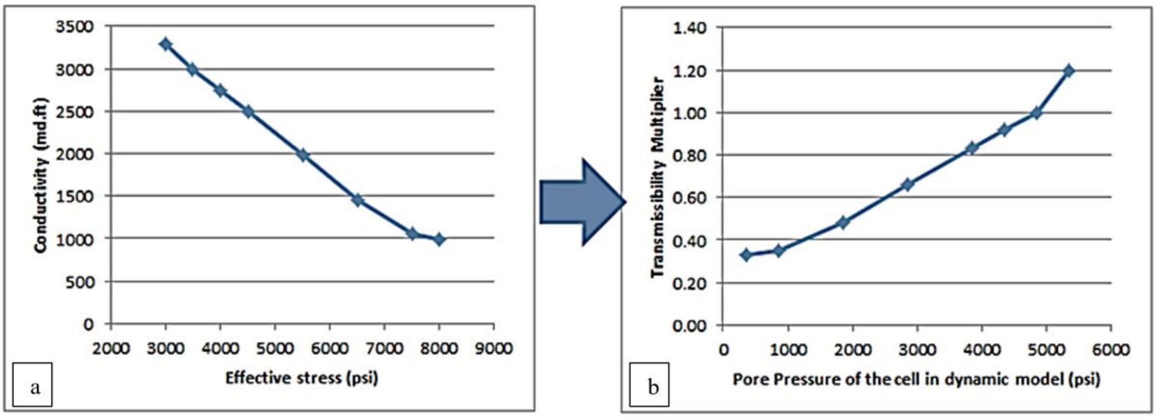

Figure 18. Translating fracture conductivity versus proppant stress (a) into fracture transmissibility multiplier versus pressure (b) [113]

A crucial step in this study is the integration of the results of net pressure analysis with the outcome of the analysis performed in this section on the change of fracture conductivity with effective stress. Such integration is considered a challenge due to the fact that the nature and detail level of these parameters and analyses are different and there has not been a practical technique to capture and successfully combine all the information gained through the application of each method. The following section presents the way in which this challenge is overcome.

E. Integration of Net Pressure Match, Well Test Data, PLT Results and Connectivity Behaviour

Generally, the process of hydraulic fracture description involves using fracture design software to match the net-pressure and report the fracture geometry (height, and half-length) and attributes such as conductivity for each fracture. Post-job well test (well test carried out after hydraulic fracturing and cleaning up) is the main reference to show the performance of the well. The problem is that the assumptions of fracture in well test interpretation are based on an average fracture attribute and geometry. This makes the comparison very difficult.

To evaluate fracture performance, we define a measurable parameter named Surface Conductivity (SC_f) for the hydraulic fractures. This parameter should be an indication of the expected fracture performance; thus, SC_f is directly proportional to fracture conductivity and its dimensions. Therefore;

$$SC_f \propto K_f . w$$

$$SC_f \propto 2 . x_f$$

$$SC_f \propto h_f$$

Where $K_f.w$ is connectivity of hydraulic fracture, x_f is hydraulic fracture half length, and h_f is hydraulic fracture height. Then, SC_f can be defined as the fracture surface multiplied by the fracture conductivity (Equation 1). The unit of SC_f would be mD.ft^3, but for simplicity of the analysis, the values would be presented in 10^6 mD. ft^3 since the typical values for such a parameter will be in the order of 10^6 to 10^9.

$$SC_f = 2x_f \times h_f \times K_f.w \qquad \text{Equation 1}$$

To generalize the concept of SC_f for the wells with more than one fracture, SC is defined for such wells as the summation of all the SC_f values of the fractures in the well (Equation 2).

$$SC = \sum_{i=1}^{n} 2x_f \times h_f \times K_f.w \qquad \text{Equation 2}$$

Integrating all the hydraulic fracture properties into one single parameter is the key advantage of SC. It can therefore, be calculated for well test analysis outcome as well as net pressure match (Equations 3 and 4)

$$SC_{WTA} = \sum_{i=1}^{n} 2x_f \times h_f \times K_f.w \qquad \text{Equation 3}$$

$$SC_{NPM} = \sum_{i=1}^{m} 2x_f \times h_f \times K_f.w \qquad \text{Equation 4}$$

where the subscript WTA denotes well test analysis (post-frac well test), NPM denotes net pressure match for the main fracture, n is the number of hydraulic fractures that are assumed for well test match, and m is the number of hydraulic fractures that are designed in hydraulic fracture design software.

In order to integrate the results from the net pressure match and well test analysis, HIF is proposed to be calculated as the SC_{WTA}/SC_{NPM} (Equation 5).

This ratio is the comparison of the product of fracture surface area ($x_f.h_f$) and fracture conductivity ($k_f.w$) between the results derived from well test analysis and net pressure matching. This ratio solves the issue of having various levels of details for net pressure match versus well test analysis. HIF is defined as:

$$\mathrm{HIF} = \frac{SC_{WTA}}{SC_{NPM}} = \frac{\left(\sum_{i=1}^{n}[2x_f \times h_f \times K_f.w]\right)_{WTA}}{\left(\sum_{i=1}^{m}[2x_f \times h_f \times K_f.w]\right)_{NPM}} \qquad \text{Equation 5}$$

This ratio is then used to adjust the fracture conductivity in the dynamic simulation model using the proposed workflow shown in Figure 19.

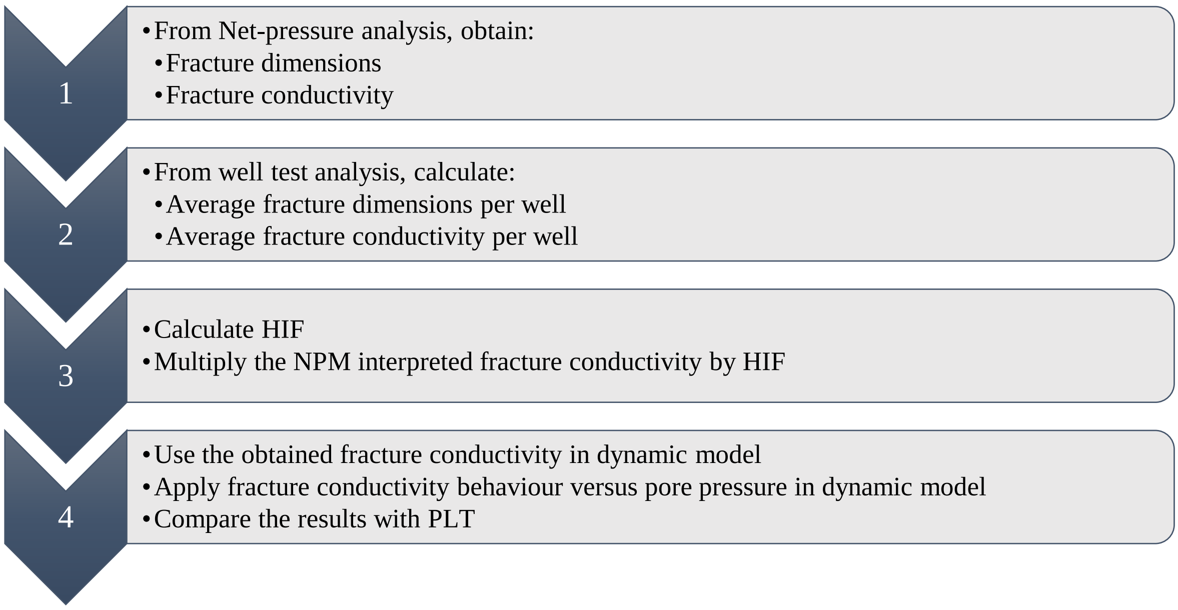

Figure 19. Workflow for integration of HIF, fracture conductivity behaviour and checking against PLT data

This technique has the following advantages:

a. It reduces the uncertainty of net pressure match output by a truth-checking scaling factor.

b. It makes history matching easier by improving initial guess accuracy.

c. It is able to correlate data from a source with fewer dimensions (well test analysis) to another source with higher level of dimensions (conductivity distribution in fracture cells).

d. It gets the benefits of both techniques: details from net pressure match and validation from well test and production data.

e. It captures the dynamics of connectivity and makes the forecasting more reliable.

This technique is validated by real field data and the results are discussed in Chapter 4.

Alternatively, the parameter α can be defined as:

$$\alpha = (\mathrm{HIF} - 1) \times 100\% \qquad \text{Equation 6}$$

HIF quantifies the heterogeneity impact on hydraulic fracture performance because it is related to the results of the observed data and considers the production period and the aerial extent of reservoir properties in comparison to what has been expected by the performance of the fracking job. Generally, when the same fracture propagation is interpreted by different engineers/ researchers, different solutions in terms of fracture half-length and height are obtained. The solutions with higher fracture half lengths usually have lower fracture height interpretations and vice versa. This gives rise to non-unique solutions for the same problem [180]. HIF analysis, however, is basically using the multiplication of the fracture half-length and fracture height, thus relaxing the solution against different interpretations. Furthermore, HIF analysis is, indeed, a repeatable workflow that can be run several times by adjusting the input parameters in their uncertainty range until the HIF uncertainty distribution is obtained based on which the rest of calculations are performed. Application of HIF in shown in a case study discussed in Chapter 4.

3.2. Production Forecasting of Hydraulically Fractured Wells Considering Reservoir Heterogeneity Effects

In order to forecast well production for heterogeneous reservoirs, two elements of forecasting and heterogeneity should be established. Arps [132] suggested the general expressions for production rate versus time as decline curve analysis. This method is focusing purely on the historical production data of the well to forecast its future production. Hyperbolic decline curve is one of these empirical formulas and can be calculated as:

$$q(t) = \frac{q_i}{(1 + b \times D_i \times t)^{1/b}} \qquad \text{Equation 7}$$

Where b and D_i are scaling constants and q_i is the initial well production rate. The value of b is in the range of zero to 1. Bahadori [181] introduced a practical workflow to arrive at an appropriate estimation of nominal (initial) decline rate, as well as the Arp's decline-curve exponent. Arp's DCA formulation has yet to be modified for heterogeneous reservoirs in such a way that it captures the impact of heterogeneity and predicts the production of other wells. Therefore, the heterogeneity effect on well performance should first be quantified.

In the previous section, HIF was introduced as a parameter for quantification of the effect of reservoir heterogeneity on hydraulic fracturing performance. Here, we use HIF as the second element required for production forecasting of hydraulically fractured wells. Once the two elements of forecasting and HIF are established, the following workflow is applied to the data available from a field including the well production data to obtain an empirical formula defined as decline curve taking into account the effect of heterogeneity (DCH):

a) Choose a well from the earliest development phase or an analogue field that has similar matrix permeability. The goal is to get the longest available historical production data for the well. Analogue fields should be similar to the targeted field in terms of porosity, permeability, fault regime, well trajectory stand-off from water contact, and other similar parameters. Such criteria need to be discussed in multidisciplinary teams to highlight the nature of the different characterisations (if any) or development techniques and the consequences of such differences on the analysis outcomes.

b) Use hyperbolic decline formula and fit a curve to the historical data to obtain q_i, b, and D_i factors.

c) Calculate HIF for this well (HIF_0); $HIF_{0=1}$ is ideal for DCH calculation.

d) Calculate HIF for the other drilled and fractured wells or use HIF from analogue fields.

e) Using Table 4, calculate the new q_{mi}, b, and D_{mi} for other wells based on calculated or assumed HIF values.

f) Use the following formula to forecast new well production:

$$q_{DCH}(t) = \frac{q_{mi}}{(1+b\times D_{mi}\times t)^{1/b}} \qquad \text{Equation 8}$$

where t is the time of production, $q_{DCH}(t)$ is the flow rate considering heterogeneity impact at time t, q_{mi} is the modified initial rate taking HIF into account, and D_{mi} is the modified decline constant taking HIF into account.

Table 4. DCH Parameters and Formula

DCH Parameters	Fitted curve parameters as reference	Formula for Low Case (if HIF<1)	Formula for High Case (if HIF>1)
Modified D_{mi}	D_i	D_i	$D_i \times HIF$
Modified q_{mi}	q_i	$q_i \times HIF$	$q_i \times HIF$
b	b	b	b

The key assumption here is that the wells are not communicating with each other. In such a case DCH will overestimate the well production rates.

DCH is an approach developed by deploying a simplified heterogeneity concept for a modified Arp's DCA. This empirical method is used to generate multi-fractured horizontal gas production profiles and is a complement to the workflows Clarkson [179] reviewed for production data analysis of unconventional gas wells to meet the demand for a faster approach which also considers the significantly complicated heterogeneity impact on well performance. A rigorous application of the proposed DCH method is discussed in Chapter 4.

3.3. Economic Evaluation of Hydraulic Fracturing

Application of the DCH method proposed in the previous section for forecasting the production from hydraulically fractured wells facilitates developing a method for economic evaluation. We propose a workflow for carrying out such an assessment in the following sections.

3.3.1. Calculation of the Cumulative Gas Production

Gas production from a hydraulic fractured well in a heterogeneous reservoir can be calculated from the empirical DCH model (Equation 8). To calculate the produced cumulative gas from a well, Equation 8 should be integrated from the start of production to a specified time:

$$G_p = \int q_{DCH}(t)dt \qquad \text{Equation 9}$$

Evaluating the integral from zero to a time t gives the following expression for cumulative gas production:

$$G_p = \frac{q_{mi}}{D_m(b-1)}\left[(1 + bD_m t)^{(b-1)/b} - 1\right] \qquad \text{Equation 10}$$

where D_m must be in 1/day unit.

3.3.2. Economic Evaluation Approach

There are different profitability indicators to evaluate the feasibility of a project from the economic standpoint. Here, the future production of a fractured well was economically evaluated through NPV calculation. NPV criterion is a robust economic evaluation tool and has been widely used in different petroleum industry projects [182, 183, 184]. The initial stage of NPV evaluation is to determine the proper parameters that encompass the objectivity of the whole process. In this way, the cash flow associated with the produced gas was calculated on the basis of expected CAPEX/OPEX and considering the economic variables such as gas price, discount rate, etc. The produced hydrocarbon selling price, CAPEX and discount rate were supposed to be the most important parameters in any gas development project. For a given CAPEX, required for drilling and stimulating a well, an income (or a revenue stream) of I_n from gas selling was expected from which the following expression can be written for NPV calculation:

$$NPV = \sum_{n=1}^{N}\left[\frac{I_n - OPEX_n}{(1+i)^n}\right] - CAPEX \qquad \text{Equation 11}$$

where i is the discount rate, OPEX is the annual operative expenditures, and N is the number of production years for which the process should be assessed. The annual revenue I_n is obtained by:

$$I_n = G_{p,n} \times GBP_g \qquad \text{Equation 12}$$

where GBP_g is the gas price and $G_{p,n}$ is the annual cumulative produced gas. $G_{p,n}$ is calculated from Equation 10 based on the difference of gas production values from time t = n to t = n+1.

3.3.3. Definition of Risk due to Heterogeneity

We propose a definition of commercial failure due to reservoir heterogeneity as the probability of having NPV<0 considering the uncertainty of HIF. To achieve this, a uniform distribution in lack of a large data set for the heterogeneity parameter was suggested. This can be tuned based on observations of off-set well production behaviour.

Given the appropriate values for CAPEX, OPEX, discount rate, and years of production, the NPV for a specified degree of heterogeneity was calculated on the annual basis. Having constructed the plot of NPV versus time for each value of HIF, the commercial cut-off or operational stopping point is selected to be the maximum NPV. This process is schematically shown in Figure 20.

Finally, the cumulative distribution plot for NPV (maximum over production time) is generated and the RCF for a hydraulic fracturing project is read from the value of zero for NPV. The results of the economical modelling including sensitivity analyses for uncertain parameters are reported in Chapter 4.

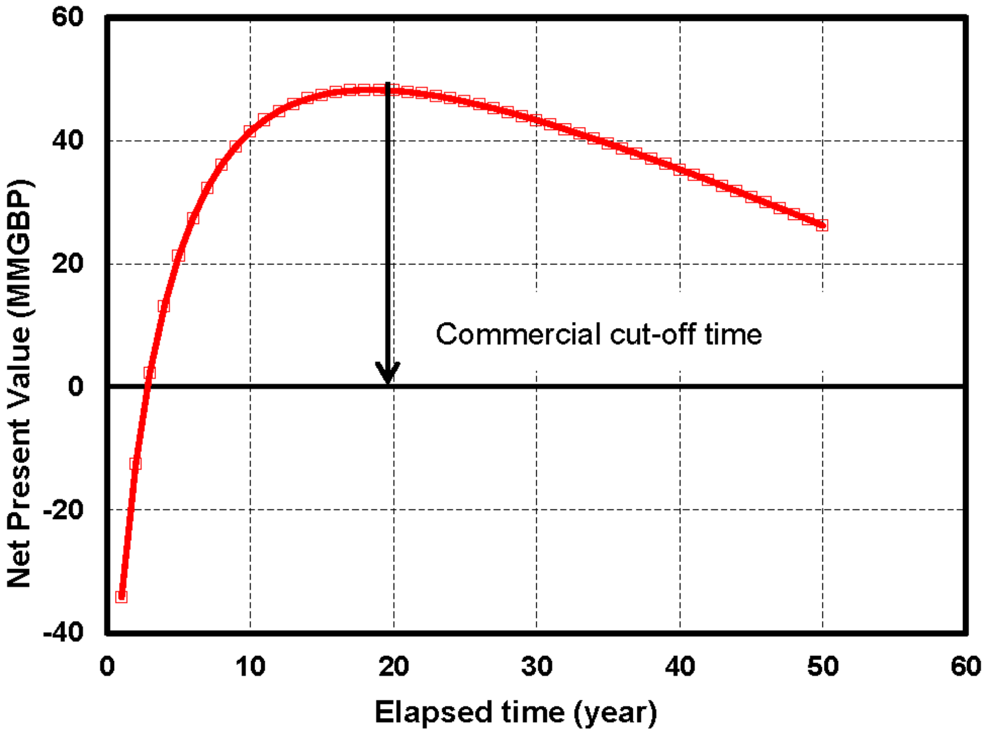

Figure 20. Selection of commercial cut off for a pre-specified value of HIF

Chapter 4. Results and Discussion

In this chapter, the methodology proposed in Chapter 3 is applied to a tight gas reservoir with hydraulically fractured wells in a case study manner. Actual field data was acquired from an oil and gas operator with the view to evaluate the hydraulic fracture performance. This field is situated in the SNS gas basin. It is 10 km long, 1.5 km wide with an estimated reservoir thickness of 270 ft. The reservoir rock is of Rotliegend age, mainly sandstone with layers of siltstone and minor shale deposits, according to log and core data. This producing horizon is overlain by a 400-feet shale formation which constrains the propagation of the fractures. The reservoir formation is also underlain by a very tight sandstone with unsuccessful attempts of production which have rendered it unexpected to have noticeable contribution to production of fluids. Based on core data, the reservoir porosity ranges from 5% to 20% and the average reservoir permeability is less than 1 mD. Slightly higher permeabilities are observed where the reservoir formation is encountered in wells at lower depths with less illitization.

The initial well test, done on the exploration well in the 1980's, had indicated a gas flow rate of 4 MMSCFD; the low rate was attributed to the significantly illitized formation. An appraisal well was drilled 16 years later and flowed 10 MMSCFD. A phased development plan was prepared with three of the five initially planned horizontal wells (A, B, and C) being drilled and fracked each with five stages. The two remaining wells were drilled after three years of production. These wells were also horizontal each with five stage frac zones (D and E), similar to phase-1 wells.

Performance evaluation of these multi-fracked horizontal wells is crucial for forecasting and evaluating further development opportunities. To simulate the hydraulic fracture in this study, pseudo 3D hydraulic fracture modelling was performed using a commercial simulator for fracture design and analysis in complex situations. However, it should be noted that, in this work, the focus is on the combined use of hydraulic fracture modelling results and pressure decline analysis results regardless of the specific methodologies/software used for obtaining such results. In other words, in any other similar study, once the fracture modelling is performed using any approach chosen by the engineer/ researcher, the results can be integrated with the results of well test analysis, which could, in turn, be accomplished using any method selected. Such integration of the results is then governed by the workflow presented here.

4.1. HIF Analysis

Through net pressure matching, an estimate of the fracture half-length x_f, fracture height h_f, fracture width w_f and its conductivity C_{fD} was achieved for the number of fracture jobs implemented in this field (Table 5).

First, as a diagnostic tool for fracked well performance, the HIF analysis is performed and cross checked with geological observations to support the conclusion. Then, production data (PLT) is shown to be in agreement with the findings of the HIF analysis. The impact of HIF on reservoir dynamic modelling is discussed in detail. Finally, the results of application of the proposed technique are validated using actual field data and evidences.

4.1.1. HIF: A New Parameter for Fracked Well Performance Evaluation

Well test interpretation has been carried out on each of the wells and the results in terms of fracture model (FC: finite conductivity), fracture conductivity (permeability×width), fracture half-length and fracture height are presented in the first section of Table 5. Interpretation of the net pressure analysis per fracture (total of 24 fractures initiated) and the outcome in terms of fracture connectivity, fracture half-length and fracture height is reported in the last section of this Table 5. HIF is calculated and shown in the middle section of the table.

HIF of 100% means the well behaves as it has been modelled. The range of HIF for this field varies from 35% to 174% which shows the wells which underperformed (Well B, D and E) or far outperformed (well A) the model. The calculated HIF values lead to observations summarized in Table 6. Furthermore, the α values obtained using Equation 6 (Chapter 3) for this field case are shown in Figure 21. This figure shows the Well A far outperformed the expected hydraulic fracture performance whereas Well D dramatically underperformed. In the next section, we discuss the geological features to confirm the results.

Table 5. Results of HIF analysis of an actual field data in addition to calculated fracture dimensions and conductivity by well test analysis and net pressure match

Well	Well test analysis per well					HIF	Net pressure match per fracture			
	Fracture Model	K_f.W (Frac) mD.ft	No. of Fractures	x_f (ft)	h_f (ft)		Average* K_f.W (Frac) mD.ft	x_f (ft)	h_f (ft)	K_f.W (Frac) mD.ft
A	FC	2500	4	300	250	174%	2039	220	230	1088
								200	220	3099
								200	120	1596
								250	180	1840
								200	240	2478
B	FC	1000	4	200	250	63%	1567	175	75	632
								210	250	403
								350	150	2169
								220	230	2106
								150	220	2008
C	FC	500	3	200	250	104%	802	200	60	195
								150	110	353
								252	198	1227
								320	160	463
								260	140	1102
D	FC	1220	3	202	150	35%	1279	420	150	2489
								350	180	1512
								580	115	601
								425	130	453
E	FC	2579	5	132	250	85%	2306	320	190	2043
								240	150	2075
								350	170	2216
								125	210	3251
								155	230	2442

Table 6. HIF analysis and explanations

Well	HIF	Explanations
A	174%	Well productivity is exceptionally higher than the expected fracturing performance.
B	63%	Well productivity is less than the expected fracturing performance.
C	104%	NPM and WTA are in a good agreement i.e. the well productivity and interpreted fracture performances are similar.
D	35%	There is a problem in the well/reservoir that causes the well productivity to be so lower than the expected performance.
E	85%	Well productivity and interpreted fracture performance are similar.

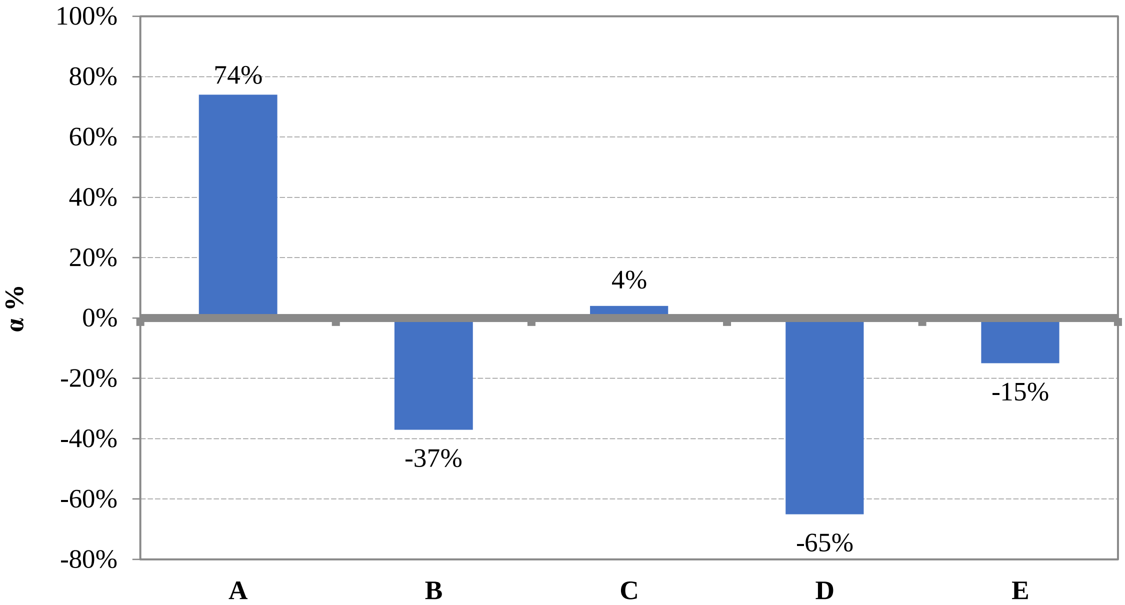

Figure 21. Calculated α values per well

4.1.2. Geological Evidences Supporting the Results of HIF Analysis

Well A has five fracturing zones in which zone 1 is the deepest and zone 5 is the shallowest, as exhibited in Figure 22. The final HIF value for Well A is calculated to be 174% which is much higher than the rest of the wells in this field. This means that there is remarkable difference between the hydraulic fracture performance expectations (net pressure match) versus the well test analysis that is related to the production behaviour over a longer period. This is an indication of the presence of an extra production mechanism that may be interpreted as natural fracture and/or more permeable sands. This interpretation is confirmed by high mud-losses observed in the drilling report and Logging While Drilling (LWD) image logs.

Static losses of approximately 41bbl/hr were observed at 13,326ft MD and dynamic losses of approximately 20bbl/hr were observed at 13,444ft MD. Based on the analysis of the density image logs, it was found that the mud losses coincide with the presence of a cluster of low-density features shown in Figure 23. The two features presented in the blue intervals of Figure 23-a and Figure 23-b were interpreted as open fractures filled with drilling mud.

Aside from the two intervals where open fractures were interpreted, there was a substantial increase in the leak-off coefficient from the mini-frac (0.0065ft/√min) in zone 4 of Well A (perforation depth interval 13280-13290 ft MD); a mini-frac is performed without proppant and used as a diagnostic to aid with the final design of the main frac job. The main-frac (with proppant) of zone 4 had the highest leak off coefficient of 0.008 ft/√min. This further substantiated the existence of a higher permeable region that is connected to the hydraulic fracture. Figure 22 illustrates the trajectory, hydraulic fractures and reported mud-loss positions during drilling.

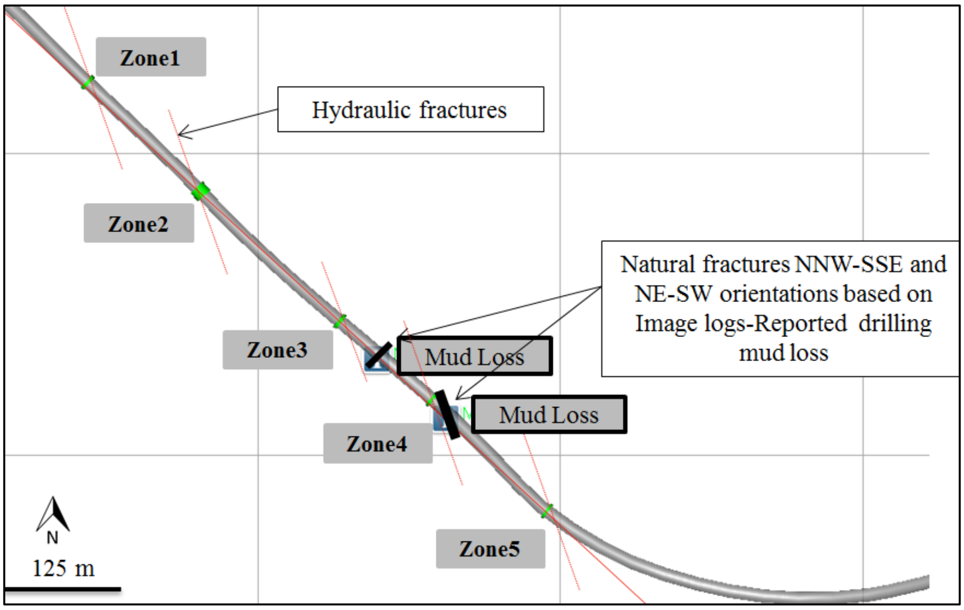

Figure 22. Well A trajectory, hydraulic fractures and mud loss positions

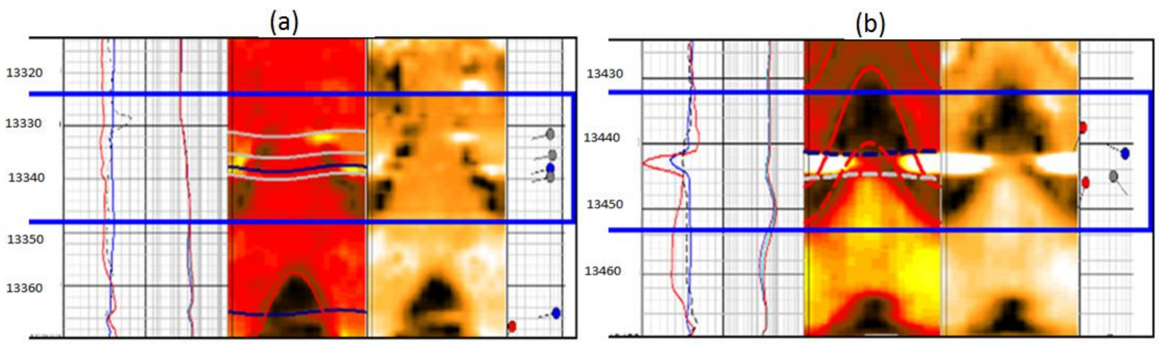

Figure 23. Density image logs show open fractures in the same regions where drilling mud losses happened while drilling Well A.

4.1.3. Production Data and Application of Proposed Fracture Performance Ratio

The PLT design was for two flowing passes, one at low rate the other at a high rate and one shut-in pass to evaluate the contribution of flow from each fracture. The tool was run in on wireline with the assistance of a tractor. Table 7 provides a summary of the PLT results for Well A.

A comparison of the SC vs PLT results is presented in Figure 24. The following observations have been made:

Zone 1: The gas flow contribution is higher than the expected fracture performance. This can be due to higher porosity at this region which needs seismic inversion techniques to be confirmed.

Zone 2: The gas flow contribution of this zone is consistent with SC_{NPM} analysis. Low fracture height caused the vertical confinement of hydraulic fracture.

Zone 3: The gas flow contribution of this zone is consistent with SC_{NPM} analysis.

Zone 4: The gas flow contribution of this zone is higher than expected fracture performance based on SC_{NPM} analysis. This is linked to the high HIF value of well A. Observations on image logs and drilling mud loss report on this zone confirmed open natural fractures.

Zone 5: This zone is not connected to natural fractures by geological evidences, but the production logging results suggest the hydraulic fractures of this zone must be connected to higher permeability conduits such as more permeable sands. In appraisal wells of this field, the more permeable sands were observed in shallower geological layers than target layers for Well A. The thickness, extension and permeability of these sands are history matching parameters for the dynamic model. Having defined all the properties and then applying the HIF analysis to longer the period of production, the history matching parameters are adjusted to obtain a geologically valid thickness, lateral extension and possible permeability of theses conduits.

Based on such analysis, HIF and production data are linked and aligned.

Table 7. PLT results summary for Well A compared with hydraulic fracture geometry from net pressure match

Zone	x_f (ft)	h_f (ft)	Fracture K_f.W (mD.ft)	SC_{NPM} (10^6 mD.ft^3)	PLT flow contribution (%)
1	220	230	1088	110	24%
2	200	220	3099	273	14%
3	200	120	1596	77	4%
4	250	180	1840	166	22%
5	200	240	2478	238	36%

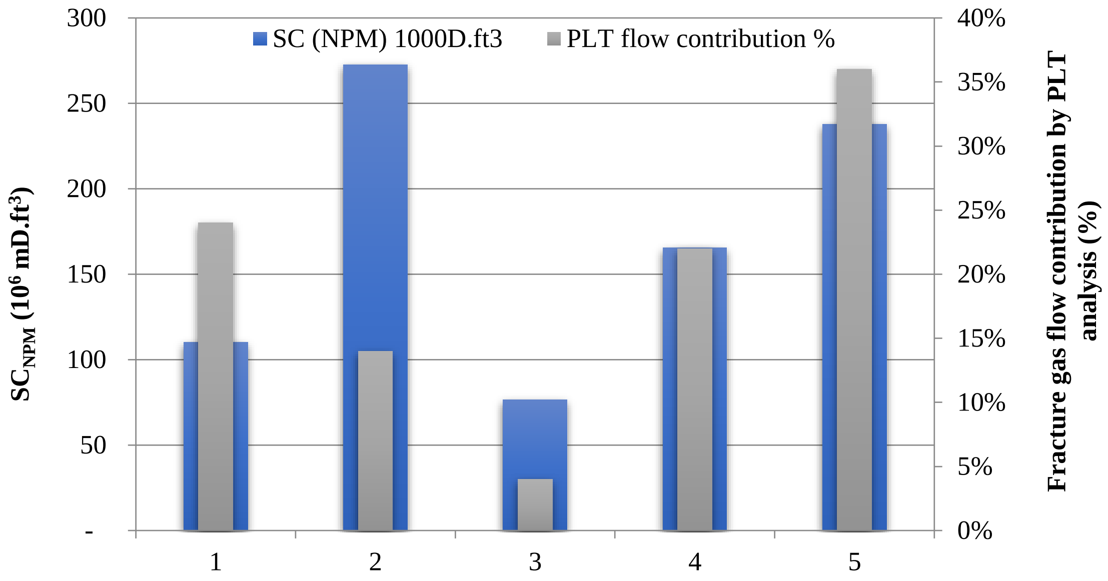

Figure 24. Comparison of SC (NPM) with PLT gas flow contribution

4.1.4. Effect of Incorporation of HIF in Reservoir Dynamic Modelling

HIF analysis identifies the wells which need to be tuned for having more reliable models. The workflow of scaling the fracture cell properties is explained in Figure 19. The dynamic model is created using the LGR method to have higher resolution around the wellbore. Having completed the workflow (Figure 19), the dynamic model should be history matched using a reservoir simulator. The reservoir simulator is run to compare the results of the input assumptions described in the above sections with the real field data. Three years of gas production data and downhole gauge data was available for this field.

The initial simulation run was close to the observed data. However, the observed data suggested that more pressure support from reservoir is required for the later production period. Well A water sample analysis report also showed a small amount of formation water production which should also be matched by the dynamic model.

In order to achieve a more representative dynamic model, the following history matching parameters for Well A were considered:

- Extension of the more permeable region in the shallower layers as observed in the appraisal well of the field
- Thickness of the more permeable region
- Connection of the more permeable region to the hydraulic fracture zones 4 and 5 to match higher gas production contribution of these zones based on the observed PLT results
- Permeability (Y and Z direction) of global cells around the hydraulic fracture zone 4 to create a higher perm connection to lower layers and also along the maximum horizontal stress. This allows a flow path for water production by representation of vertical open natural fractures which most likely are oriented in the maximum horizontal stress direction.

Using the above history matching parameters, the dynamic model was tuned and a match of gas production rate, bottomhole pressure, production contribution of each zone and water production rate was achieved. Figure 25 shows Well A along with five hydraulic fractures and water saturation increase in Zone 4 due to its connection to natural fractures. The hydraulic fractures connect to an extensive higher permeable region and natural fracture network, a 150 mD high-permeability region is applied in four sub-layers connected to zones 4 and 5 up to 200 m around Well A. This area is illustrated in Figure 25 as the cells with green colour.

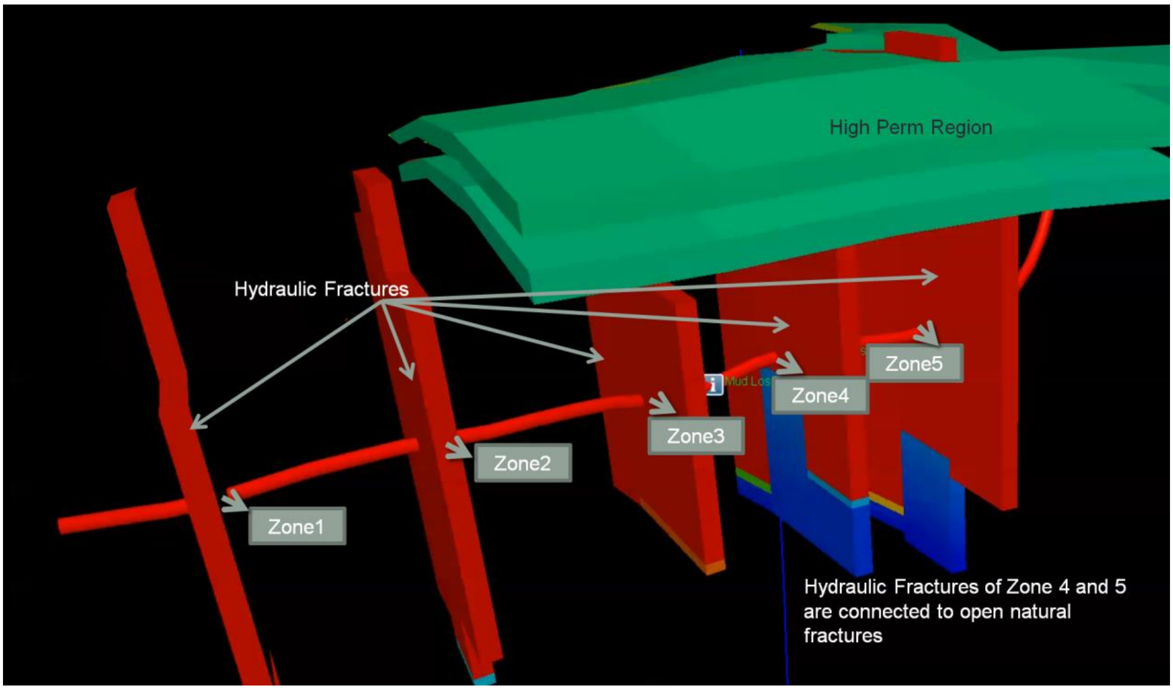

Figure 25. Water saturation on hydraulic fractures of Well A after history matching

4.1.5. Validation of Proposed Technique using Actual Data

In order to validate the dynamic model, the pressure during the next summer shut-down is predicted. Shut-in pressure data analysis is widely used in reservoir engineering to describe the production mechanism not only in the close proximity of the well but also in distances further away from the wellbore. The pressure difference and Bourdet derivative on a log-log plot is one of the key diagnostic plots in such an analysis. Matching these plots can demonstrate the accuracy of the model and it is ideal to validate the dynamic model. Therefore, a simulation of shut-in buildup data was performed during the summer shut-down that lasted around three weeks (Figure 26). Comparing the simulation data to real observed data in Well A, a reasonable match was found, where the bilinear flow regime represents the finite conductivity fractures (1/4 slope), followed by a transition to a compound linear flow (1/2 slope).

The dynamic model is not supposed to match the early time data due to the effects of wellbore storage. However, it should match the pressure differences in the middle to late time regions and ideally the Bourdet derivative. Figure 26 illustrates such a match, which is an evidence for validation of the model.

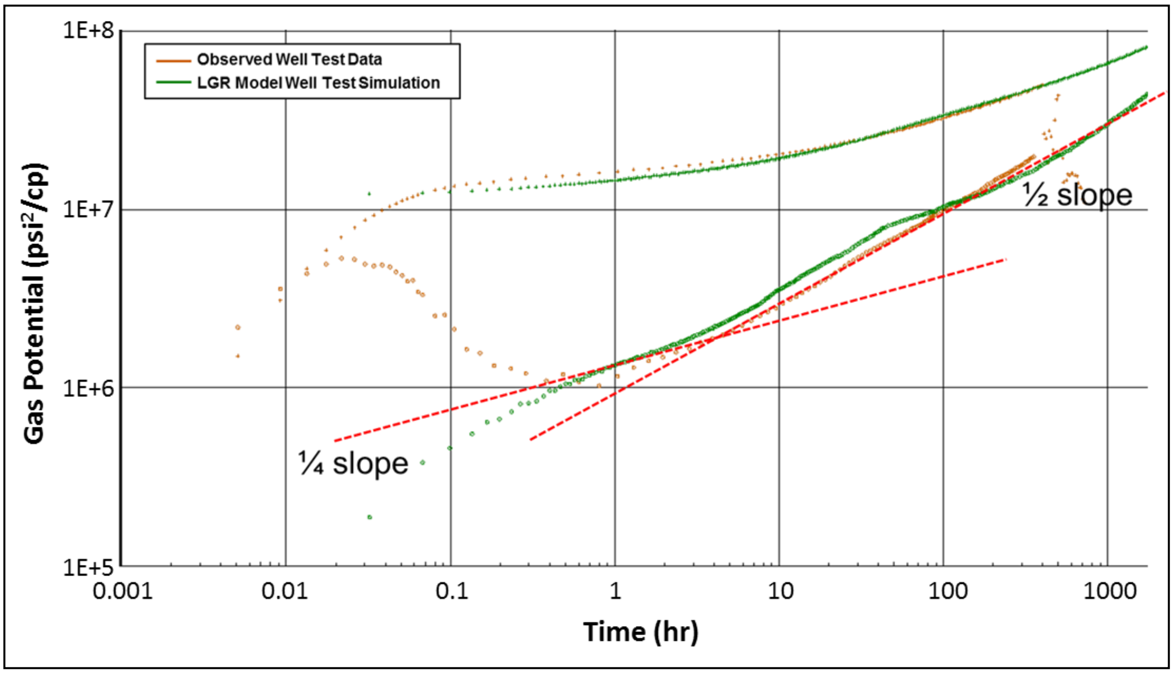

Figure 26. Pressure derivative of LGR model prediction versus observed shut-in data for Well A

4.2. DCH Technique

Initially, 5 years of production data of 3 multi-fractured horizontal wells of the SNS reservoir under the study was considered (Figure 27). The well test data of these wells are tabulated in Table 8. The analysis of fracturing operation data and using net pressure matching leads to the results given in Table 9.

Using Equations 3 to 5, it is possible to calculate the HIF for each well (see Table 10). As it is clear in Table 10, Well 2 is considered as the reference well in the current investigation since the calculated HIF for this well is close to unity. Using Equation 7, a hyperbolic decline curve is fitted to the gas production rate of Well 2 and extrapolated to forecast future production rates, as shown in Figure 28. DCH calculations are shown in Table 11.

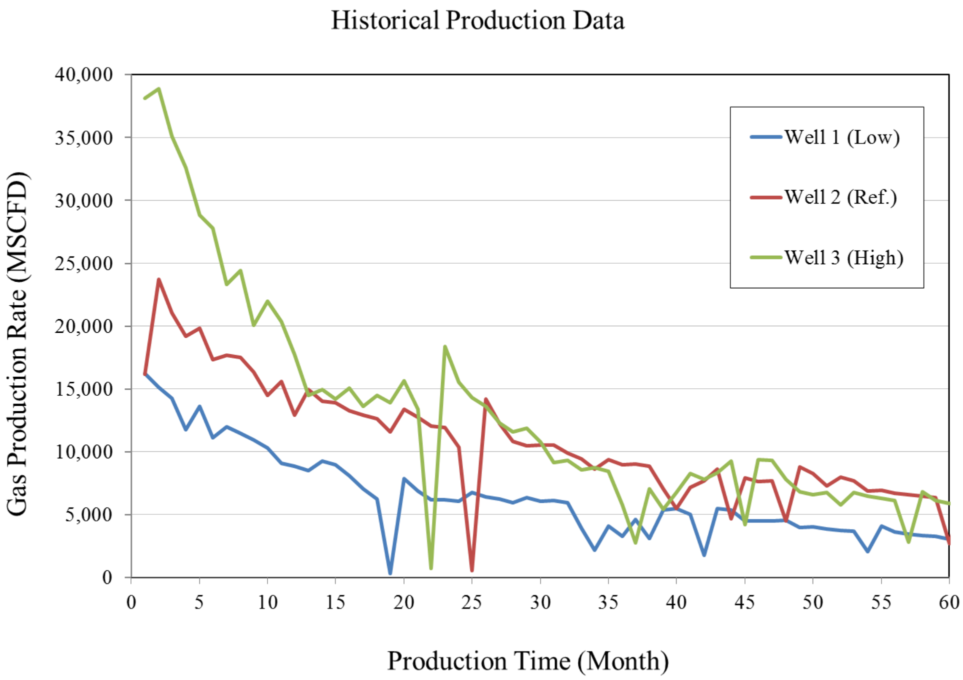

Figure 27. Five-year well production data of three multi-fractured horizontal wells

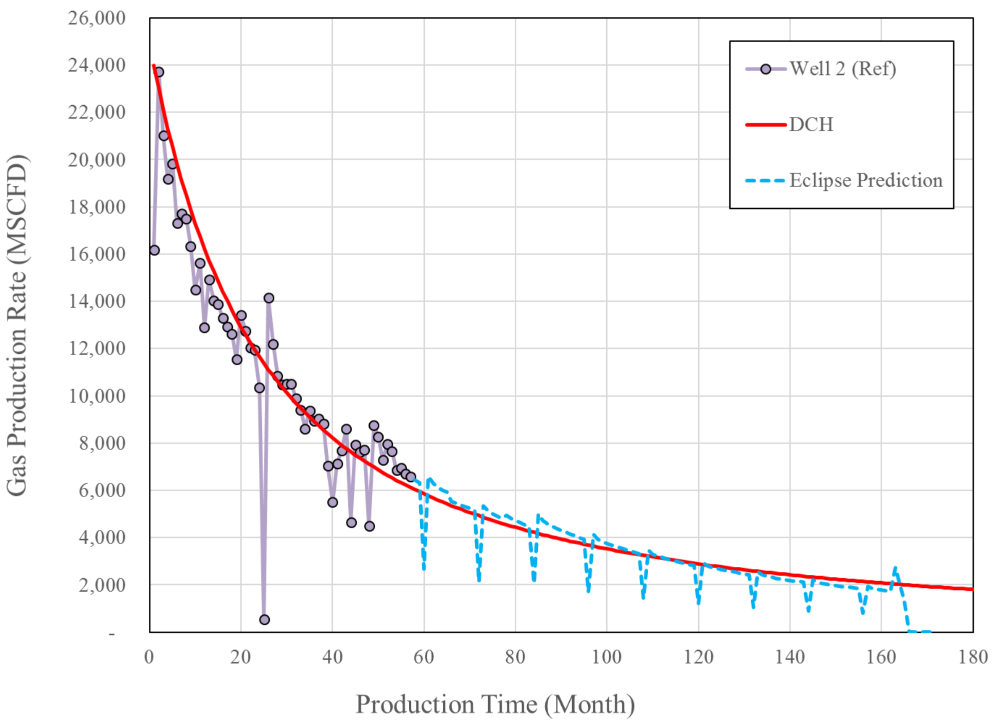

Figure 28. Well 2 historical production rates matched with DCH and Eclipse predictions

Table 8. Well test analysis per well

Well	K_f.w (Frac) mD.ft	No. of Fractures	x_f (ft)	h_f (ft)
1	1000	4	200	250
2	500	3	200	250
3	2500	4	300	250

Table 9. Net pressure match per fracture

Well	K_f.w (Frac) mD.ft	x_f (ft)	h_f (ft)
1	632	175	75
	403	210	250
	2169	350	150
	2106	220	230
	2008	150	220
2	195	200	60
	353	150	110
	1227	252	198
	463	320	160
	1102	260	140
3	1088	220	230
	3099	200	220
	1596	200	120
	1840	250	180
	2478	200	240

Table 10. HIF values for each well

Well	HIF
1	0.63
2	1.04
3	1.74

Table 11. DCH Calculation for wells 1, 2 and 3

DCH Parameters	Fitted curve parameters as Reference	Formula for Low Case HIF=0.63	Formula for High Case HIFr=1.74
Modified D_{mi}	D_i=4.20%	D_i=4.20%	D_i*HIF=7.31%
Modified q_{mi}	q_i=25000 MSCFD	q_i*HIF=15750 MSCFD	q_i*HIF=43500 MSCFD
b	b=0.70	b=0.70	b=0.70

The area between the two graphs in Figure 28 is an indicator as to the matching suitability of the DCH method. In this case, DCH predictions have been compared against the predictions made by Eclipse reservoir simulation software [185], and there is about 4% difference between the cumulative gas production of the two predictors (See Table 13). This difference is mostly due to the exclusion of the well's production schedule in the DCH calculation. In case of making predictions on future forecasts of the same production schedule, this assumption is appropriate and the collected information from DCH is sufficient. In the high case in Table 11, D_i is multiplied by HIF to account for the increased depletion caused by the accelerated production. Using the DCH formula, predictions for well 1 and well 3 are calculated and shown in Figure 29, Figure 30, and Figure 31. The results obtained for wells 1 and 3 show acceptable and reasonable matches between the DCH prediction and the historical production data for cases where the performance of the well is significantly affected by its heterogeneity.

The proceeding phases of this field development can also be predicted faster by the DCH method than the high-powered numerical simulation. For example, in the next phase of this field development, another well was drilled and fractured. Although this well has production data for a short period (only 30 months) an attempt was made to compare the DCH prediction with the real production data. Table 12 shows the results of the well test and net pressure match analysis for this well. A quantitative comparison of the cumulative productions from DCH and numerical simulation using Eclipse is another indicator of the DCH prediction suitability. In this case, there was a negligible difference of about 3% between cumulative gas production predictions of the two predictors (Table 13 and Figure 32).

Table 12. The well test and net pressure match analysis results for Well 4 DCH calculation

Well test analysis for well #4				Net pressure match per fracture		
K_f.w (Fracture) (mD.ft)	No. of Fractures	x_f (ft)	h_f (ft)	x_f (ft)	h_f (ft)	K_f.w (Fracture) (mD.ft)
1220	3	202	150	420	150	2489
				350	180	1512
				580	115	601
				425	130	453

Table 13. Cumulative gas production of the predictors and the difference

Predictions	Well 1	Well 2	Well 3	Well 4
Cumulative Gas Production DCH (Bcf)	18.3	29.5	34.7	10.3
Cumulative Gas Production Eclipse (Bcf)	15.5	28.3	32.5	10.6
Difference (%)	15%	4%	6%	-3%

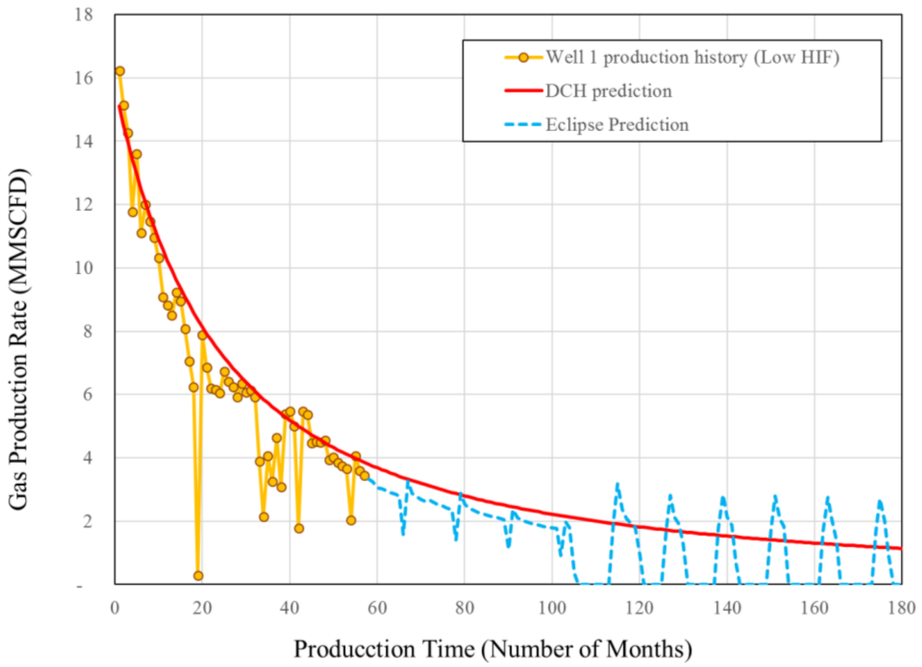

Figure 29. DCH matched with Well 1 historical production rates and Eclipse predictions

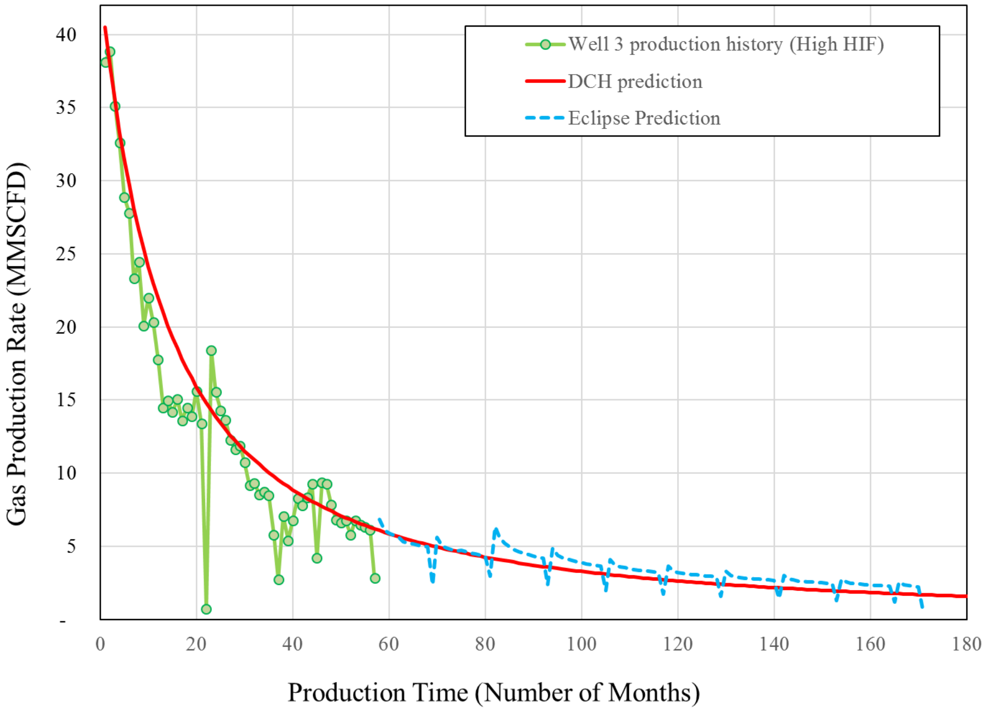

Figure 30. DCH matched with Well 3 historical production rates and Eclipse predictions

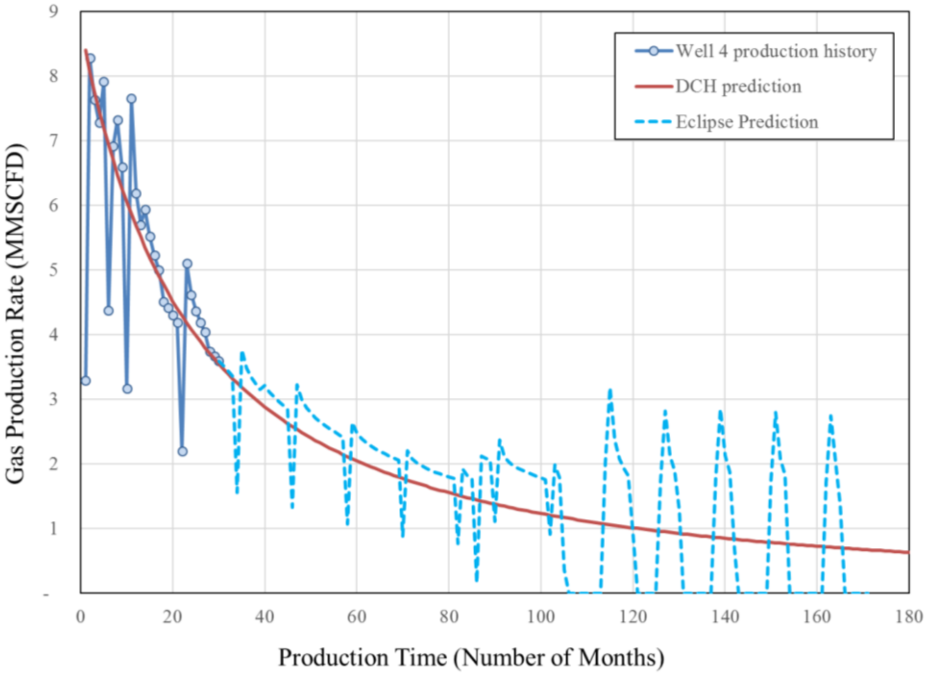

Figure 31. DCH matched with Well 4 historical production rates and Eclipse predictions

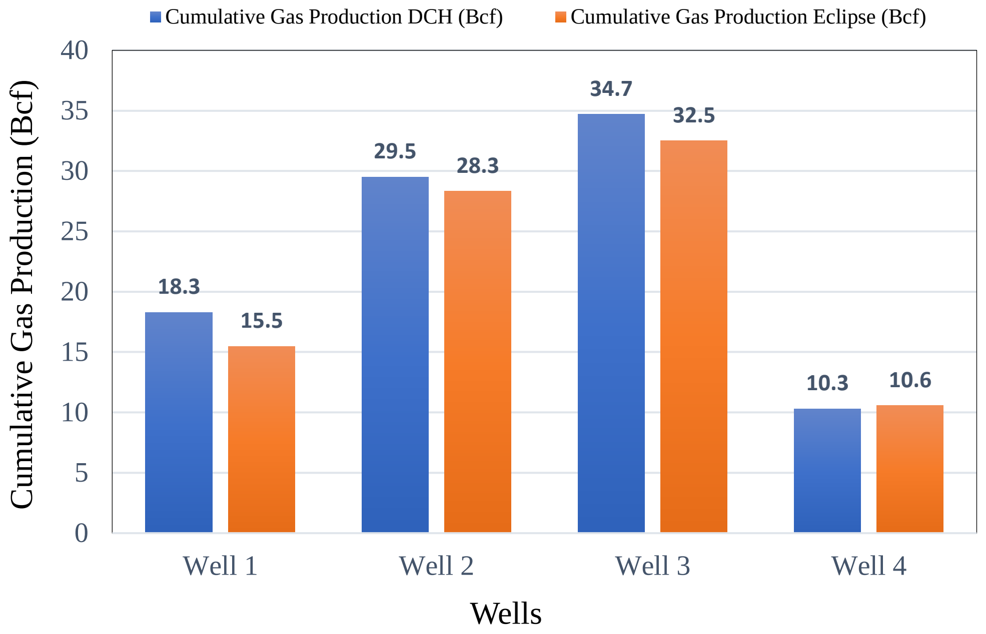

Figure 32. DCH Cumulative gas production versus Eclipse predictions

The DCH method is much faster both in terms of modelling preparation and simulation runtime than conventional 3D modelling methodologies (See Table 14). The fact that HIF is the only key parameter representing the heterogeneity impact, makes it very easy to run different scenarios and generate production profiles for uncertainty analysis.

Table 14. Comparison of the timing for DCH versus a conventional methodology

Activities	Time
DCH study and modelling preparation	2 weeks
DCH run time	<1 second
3D modelling preparation	4 months
Eclipse run time	3 hours

HIF represents the influence of heterogeneity on well performance. A positive HIF value means well test interpretation exhibits presence of extra supports for production, considering the fact that well test reflects the overall remoter behaviour of well-reservoir interaction compared to net-pressure-match result which is at the proximity of the well-fractures. Lower HIF values display less support for well production due to heterogeneity. Thus, an attempt has been made to explore the relationship between the matched DCA parameters and HIF for the observed data of different wells.

The higher HIF corresponds to higher than expected observed initial production rates. For a negative HIF, just multiplying DCA's initial production rate of base case by the HIF value led to a match of the corresponding well behaviour. For cases with HIF>1, this is more complicated as the depletion effect should be considered as well. When the initial rate is higher, the depletion is accelerated, and a faster decline is expected due to higher cumulative production. Hence, the DCA decline factor is also multiplied by the HIF value. This could match the well behaviour for positive HIF cases. Based on the well production data, DCH has been developed, and then the data for well 4, which has been drilled and completed in the proceeding phase of development, has been tested to see if DCH exhibits a reasonable match. It appeared that cumulative production data of well 4 is only 3% different from the corresponding numerical simulation results which are assumed as reference for comparison with the DCH results.

It should be noted that the objective of this approach is to have a faster method to capture a wider range of production forecasts in order to model the massive uncertainty of well production forecasting due to heterogeneity for undrilled wells and lay the foundation for such works. For this objective, a higher degree of error is acceptable as the general pattern of hundreds of forecasts shall remain quite unaffected due to slight over- or under-predictions. The proposed DCH approach is recommended based on observed field data in tight sand reservoirs and it is esteemed that more research can be exercised to extend the idea for the other type of formations such as shale reservoirs where the influence of transient behaviour is dominant.

It is worth mentioning that the detailed physics for interaction of induced fractures with existing natural fractures are not modelled as conventional simulation techniques such as finite difference applied here does not cover such details. The overall behaviour of the wells, though, has been modelled, because historical data was available. The hydraulic fracture and matrix properties have been tuned slightly to capture the overall behaviour and match the well performance. This has no effect on the results because of the order of details.

4.3. Economic Evaluation

In this section, the results of the economical modelling including sensitivity analysis for uncertain parameters are reported.

4.3.1. Assumption of Model Variables

HIF. To have a reasonable corresponding range for HIF, we refer to our recent investigation in the previous section (Section 4.2) in which the impact of heterogeneity on hydraulic fracturing performance was discussed. Based on the HIF determination framework applied for the available real field information from fracked wells drilled in the SNS reservoir under the study, the obtained values for HIF were in the range of 0.35 to 1.73. Therefore, this interval was selected for NPV calculation in the following sections.

Cost and income assumptions. The capital and operating expenditures, gas price and discount rate are four main parameters in determining the profitability of a hydraulic fracturing job. The CAPEX is mainly the cost of the well construction (including drilling and completion activities), fracking fluids preparation, pipe line and pumping facilities, and proppants. Whether a well was drilled from an offshore platform or not affects the CAPEX to a significant extent. Based on recent commercial activities in North Sea [186], a representative range for CAPEX was selected to be 30–60 MMGBP with mid value of 45 MMGBP. In addition, a fraction of annual income is spent as OPEX (1–4 MMGBP per year). As another effective parameter, the gas price depends on different factors such as global/local demands and types and/or issues of contracts. It can be interrelated to the crude oil prices and changes with the increase/decrease in global oil price. However, the situation of no relation between oil and gas price was also encountered.

Although the prediction of gas price is complicated, the economic evaluation of hydraulic fracturing is linked to cash flow resulted from the selling price of the produced gas. Therefore, one must estimate the price upper and lower bound to account for the commercial risk to some extent. Different gas prices reported for North Sea in recent years imply that a range of 4–6 GBP per MMSCF can be considered. The discount rate reveals the decrease in the value of future income. Some aspects such as the inflation and interest rate were taken into account by this parameter. For our case, in an optimistic low-risk condition for investments, the discount rate was supposed to be 0.05. In the high-risk environment, this value was allowed to be raised up to 0.15. Table 15 summarizes the uncertainty ranges for the economic parameters discussed above.

Table 15. The uncertainty range for the sensitivity analysis

Input Parameter	Low Value	Mid Value	High Value	Unit
CAPEX	30	45	60	MMGBP
OPEX	1	2	4	MMGBP/Year
HIF	0.35	1	1.75	-
I (discount rate)	0.05	0.1	0.15	Yearly
GBP_g (gas price)	4	5	6	GBP/MSCF

4.3.2. Sensitivity Analysis

As discussed earlier, the values of economic parameters were subject to a degree of uncertainty in a reasonably pre-specified domain. Therefore, the dependence of the model response, i.e., NPV, on change in parameter values should be clarified. In this regard, a sensitivity analysis stage was performed through so called one-at-a-time approach. A given parameter was set to its lower and upper bound values when the rest of variables took their midpoint or base values. The results were emerged as a famous tornado chart. The related plots are shown in Figure 33 in which the effect of the four discussed economic variables as well as the HIF value was explored. To better understand the significance of each parameter, the change in maximum NPV was normalized according to the base NPV value (considering the mid values for parameters). Indeed, the reported NPV in Figure 33 shows the fraction of increase/decrease in initial NPV due to change in a given parameter.

Although the whole project should be evaluated based on the maximum NPV, tracking the NPV history (i.e., the change in NPV over the production life of a given well) could lead to valuable insight into the individual role of contributing parameters. To achieve this goal, the sensitivity of NPV on different parameters was illustrated at the end of the 5th, 10th, 15th, and 20th years of production. Since the CAPEX is a constant cost paid at the initial stage of project, the variation of NPV due to the change in CAPEX did not depend on the time, and the tornado chart, in this case, showed approximately no variation.

The minor change in CAPEX around ± 0.5 was due to change in the base NPV at the end of each specified time interval. The OPEX and discount rate were defined on an annual basis and so they did affect the NPV over time. Gas price was not assumed a time dependent variable but it impressed the NPV history due to increase in the cash flow related. The tremendous impact of HIF on the NPV change with time was undeniable but the situation was more remarkable as the HIF was not a transient variable. Dealing with the positive effect of parameters on NPV, one could find that the effects of different parameters tend to be somehow comparable. However, the negative effect was more pronounced in the case of HIF. Strictly speaking, the HIF was a time-independent parameter that influenced the profitability of the hydraulic fracturing project during the whole life time of the well/reservoir. The evaluation also demonstrated the significant role of heterogeneity on maximum NPV.

The evaluation also demonstrated the significant role of heterogeneity on maximum NPV. In the same way, Figure 34 shows that the low HIF can erode the project value much stronger than adding significant project value by higher HIF. Table 16 shows the results of maximum NPV calculation using uncertainty ranges presented in Table 15.

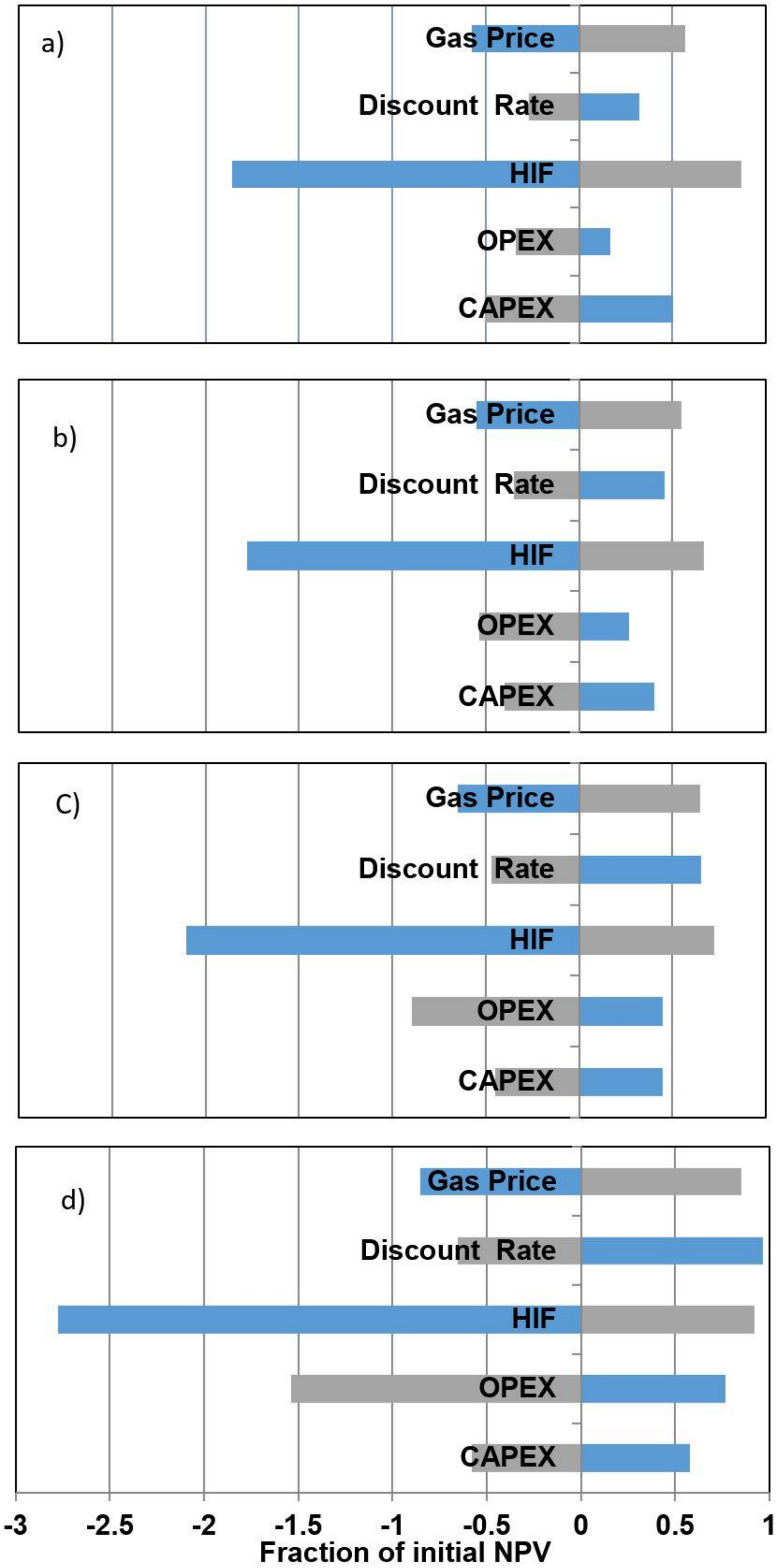

Figure 33. Variation of NPV over time for change in different economic parameters and HIF. (a) End of the 5th year of production; (b) End of the 10th year of production; (**c**) End of the 15th year of production; (d) End of the 20th year of production.

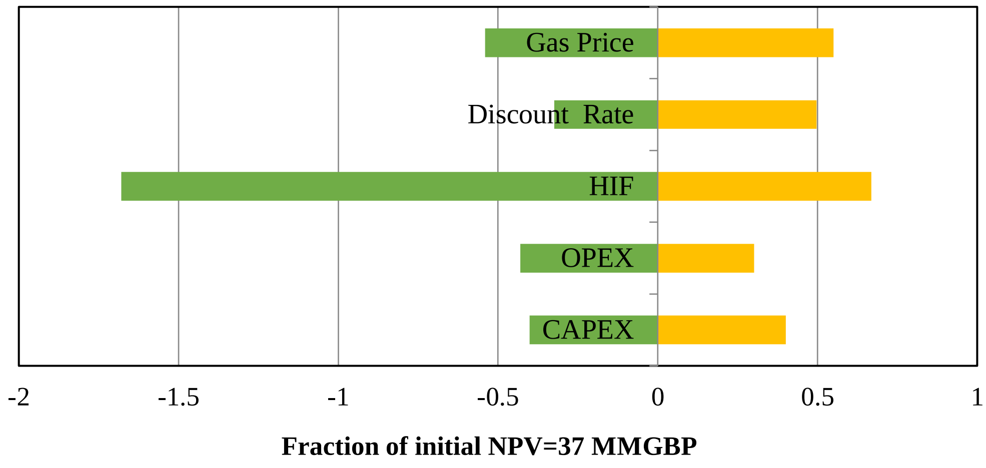

Figure 34. NPV sensitivity analysis showing the significant role of HIF parameter

Table 16. Sensitivity analysis results. Different values are color coded with colors ranging from red (representing the lowest NPV value) to dark green (representing the highest NPV value)

Parameters	Maximum NPV [MMGBP]		
	low value	Mid Value	high value
HIF	-25.4	37.4	62.4
GBP_g (gas price)	17.2	37.4	58
I (discount rate)	25.3	37.4	56
CAPEX	22.4	37.4	52.4
OPEX	21.3	37.4	48.7

4.3.3. Modeling

To model the RCF associated with a hydraulic fracturing project considering the heterogeneity of the gas reservoir, the workflow presented in Figure 35 was followed.

Using the field data, and observed range of HIF from 0.35 to 1.75 for the wells, the model has been set up for 100 realisations of uniform HIF distribution with mid value assumptions of Table 15. The NPV versus time for each scenario has been calculated. Figure 36 demonstrates NPV versus time for the base case.

This figure clearly demonstrates the very positive value of the project by year 10 which is the commercial cut-off for this scenario.

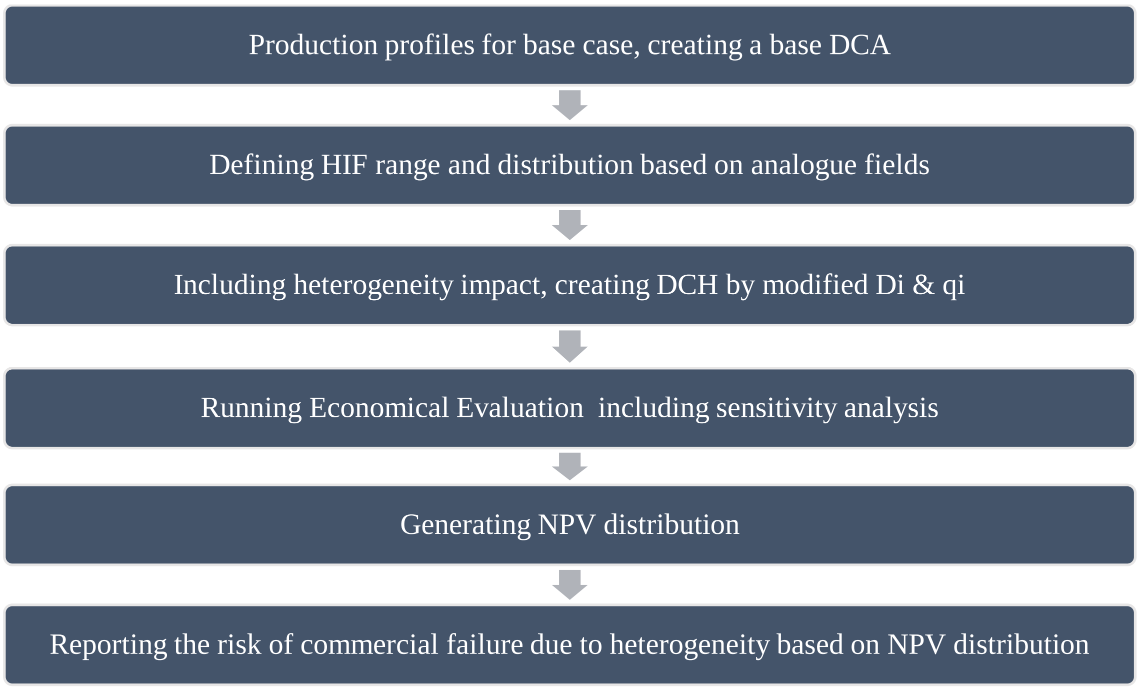

Figure 35. Workflow of RCF calculation

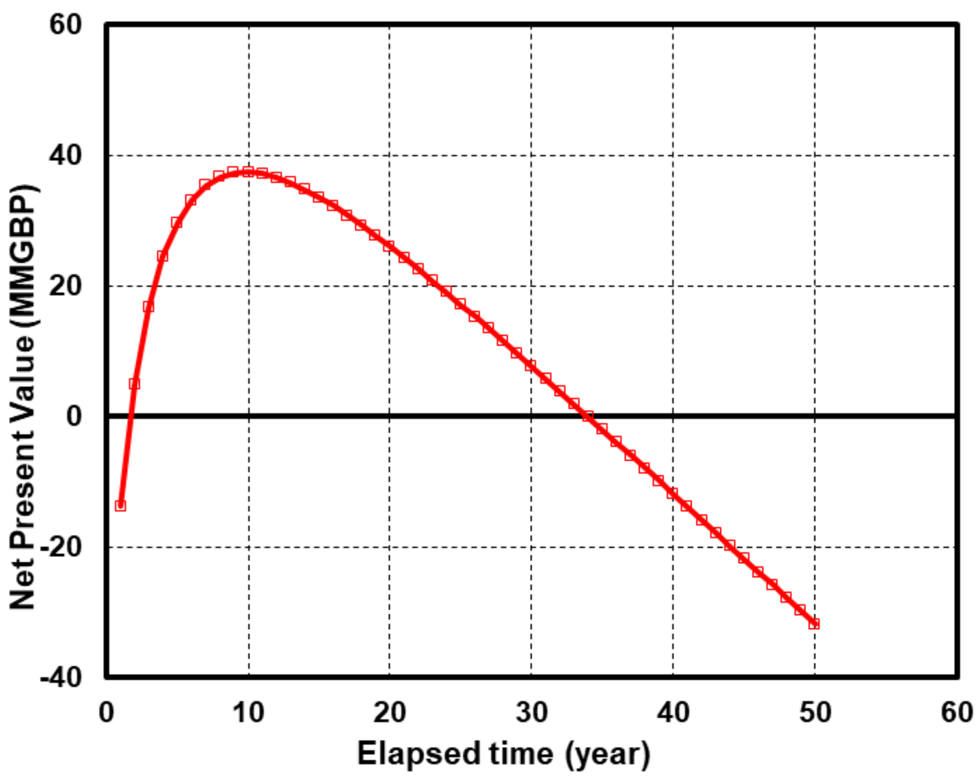

Figure 36. NPV versus production time for base case (HIF=1)

The commercial cut-off of each realization was calculated and reported for positive NPVs (8 to 10 years) versus HIF (Figure 37).

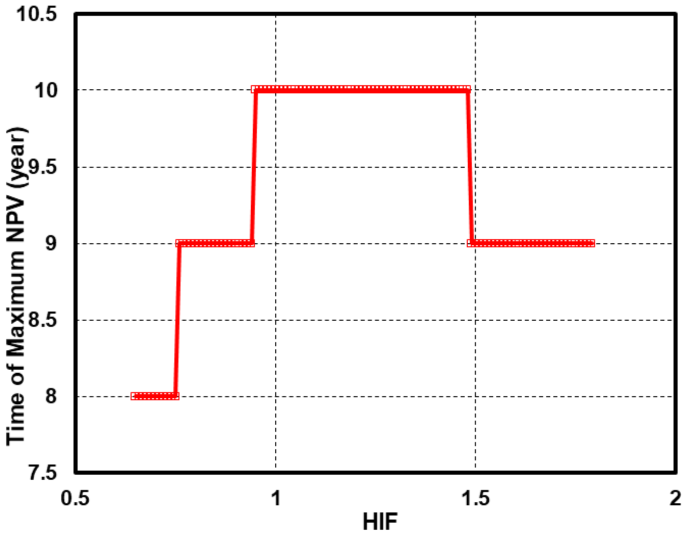

Figure 37. Commercial cut-off years after production versus Heterogeneity Impact Factor

Finally, the cumulative probability of NPV was calculated using 100 realizations and P10, P50, P90 were reported as 60, 40 and -12 million GBP (Figure 38). The proposed term for the chance of commercial failure for this hydraulic fracturing project due to heterogeneity is 1 minus the intersection of NPV=0 and the cumulative NPV probability, i.e. 20%.

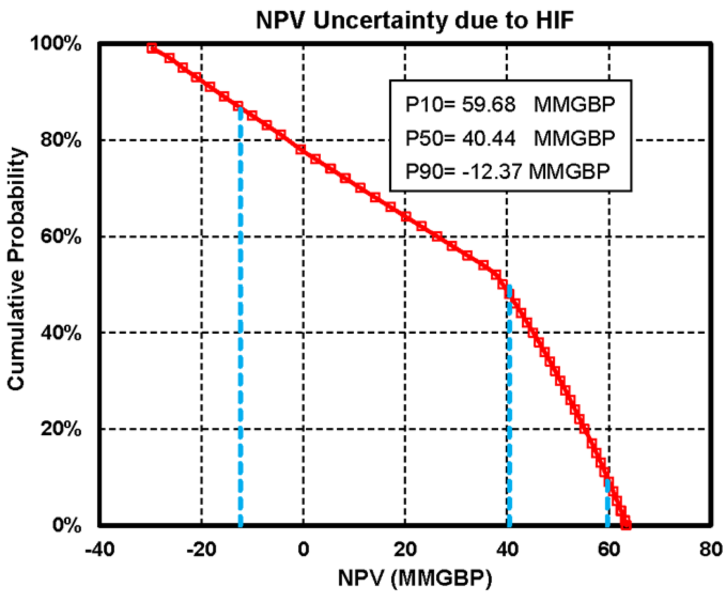

Figure 38. Cumulative probability distribution of NPV

4.3.4. Validation

The validity of RCF is evaluated for the reservoir under the study. As discussed before, the field has five multi-fracked horizontal production wells. The NPV per well has been calculated to demonstrate any commercial failure of well development due to heterogeneity which is the only differentiator in this case. The cost and forecast assumptions are presented in Table 17.

Table 17. Economic and forecasting assumption

Input Parameter	Value	Unit
CAPEX per well	45	MMGBP
OPEX per well in this field	2	MMGBP/Year
qi	25000	MSCF/d
GBP_g (gas price)	5	GBP/MSCF
I (discount rate)	0.1	Yearly
D	4.2	% Monthly

Having analyzed the well production data, the corresponding DCH values have been developed which in turn led to the HIF matching per well as shown in Table 18.

Table 18. Matched HIF per well

Well No	HIF
1	0.35
2	0.65
3	1
4	1.75
5	1.4

The corresponding values of parameters utilized to calculate the gas production from these five hydraulically fractured wells were then evaluated as presented in Table 19.

Table 19. Values of different parameters utilized to calculate gas production

Well No.	HIF	q_{mi}	D_{mi}	b
1	0.35	8750	4.2	0.7
2	0.65	16250	4.2	0.7
3	1	25000	4.2	0.7
4	1.75	43750	7.35	0.7
5	1.4	35000	1.95	0.7

The economic evaluation based on the values given in Table 17 resulted in maximum NPV values of -25.4, 2.5, 37.4, 62.4, and 52.4 MMGBP for wells 1 to 5, respectively (Figure 39). Considering the positive value of NPV as the project successfulness criterion, one well out of five failed to be commercial due to heterogeneity as the design of the wells were almost identical. This corresponded to the value of 20% for RCF obtained in the previous section.

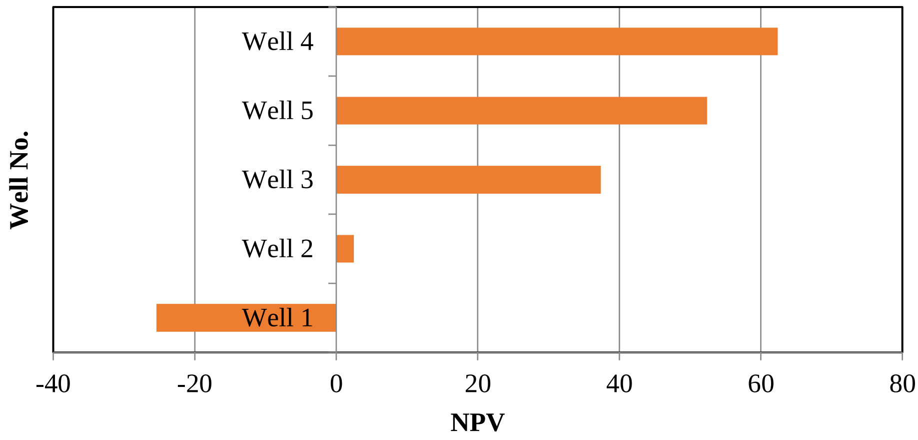

Figure 39. Maximum NPV for 5 wells drilled in the reservoir under the study

Chapter 5. Conclusions and Recommendations

5.1. Conclusions

Based on the work done as presented in this thesis the following points are concluded:

- Various sources of information and analysis such as well test interpretation, net pressure study, fracture production data, fracture conductivity performance versus effective stress and reservoir dynamic modelling were discussed. The technical gap in data integration was identified and the HIF technique was proposed as a primary solution for quantification of the impact of heterogeneity on the performance of hydraulic fracturing in wells of tight formations.

- HIF analysis integrates the outcomes of well test interpretation and net pressure analysis in order to establish a quantitative diagnostic parameter for heterogeneity evaluation. This parameter is also used for scaling the NPM fracture conductivity to better represent the fractured well performance behaviour. The dynamic model initialized using such scaled fracture conductivity is more reliable.

- HIF defined in this study represents a quantified value for the expected performance of hydraulic fracturing on each well. This quantified value represents the contribution of heterogeneity and creates a basis for comparing the wells of the same field with each other. It can also exhibit the impact of heterogeneity between different fields.

- The proposed technique of HIF analysis was applied on real field data of a SNS reservoir and the results were presented in the thesis. Successful application of the method in this case study shows the robustness of the technique. As an evidence for validation of the dynamic model, model prediction was compared with a future 3-week shut-in pressure. The buildup pressure response and its derivative displayed an excellent match between the simulated and observed results.

- This research further demonstrates a practical integrated approach towards modelling and evaluation of hydraulic fracturing performance in heterogeneous reservoirs. The proposed DCH approach provides a sufficiently representative trend of the production performance of the wells and, as such, can be used to forecast and make future decisions via a fully empirical method that abstains from costly and time-consuming numerical simulations.

- Hydraulic fracturing economical evaluation at the low energy price era is more complicated and an appropriate decision-making process for such projects requires integration of technical forecasting including uncertainty analysis with economical models. Such models are very time consuming to implement if they include three-dimensional reservoir property variation.

- An empirical approach (the HIF analysis) was suggested in this study to capture the heterogeneity using well-test analysis and net-pressure-match interpretations. Then a new set of decline curve analysis formulas linked HIF to forecasting (the DCH method). As the final step, a time-efficient workflow is proposed to capture the uncertainty of HIF using real data from a tight field in SNS, along with a set of formulas for NPV calculation including commercial cut-off and calculation of NPV probability distribution, and, ultimately, a newly defined insightful parameter called RCF which quantifies the risk of commercial failure of the hydraulic fracturing project due to heterogeneity. RCF was calculated as 20% for the next phase development of a real field case.

5.2. Recommendations

The author humbly recommends the following points as areas of further research based on the findings of the current work and methods and workflows proposed in this dissertation:

- **Comparison of well performances due to heterogeneity based on HIF.** Quantification of the heterogeneity impact as a value is important as this value can be used for prediction of well production by integrating the HIF analysis with the production simulation. HIF can be used to compare the performance of different wells only based on heterogeneity of the rock and filter the higher performance wells versus the other wells. This can help to analyze the patterns across different wells of the field and identify the best drilling targets for the next phases of field development.

- **Determination of spatial and zonal heterogeneities in the field.** Successful application of the proposed HIF analysis has been confirmed by the geological and drilling evidences of encountering zones of natural fractures or high-permeability streaks. This implies that the HIF analysis can prove valuable in gaining insight to the degree of such zonal heterogeneities which might be expected in other parts of the field in case of the absence of enough geological or drilling information. In this sense, HIF analysis, once performed for a sufficient number of wells in a field, could serve as a powerful guide in better realizing (or at least expecting) the reservoir heterogeneity by considering the range of HIF values for the wells in different locations of the field.

- **Comparison of different production scenarios based on HIF-based uncertainty analysis.** HIF can be used in uncertainty analysis of well production predictions as it gives a range of possible outcomes and, by linking to decline curves analysis, it can generate hundreds of scenarios in a few minutes. This is also another area of future work for the researchers.

- **More robust algorithms for reservoir heterogeneity modeling.** The accuracy of the proposed DCH method is apparent in the similarity between the DCH predictions with ECLIPSE predictions for the gas production rate. In these estimations, the DCH prediction deviates by a maximum of 15% from predictions of numerical simulation using ECLIPSE. This margin of error is reasonable in comparison to the substantial reduction of lengthy simulation procedures. Furthermore, in case the dynamic model of the reservoir is still not made, the DCH method can be used reliably to provide production forecasting. Given a larger quantity of information, the algorithms can be tuned to act more robustly by considering more parameters when modeling the heterogeneity of the reservoirs.

- **Incorporation of the proposed workflow in reservoir simulators.** The workflow presented in this research has three main constituents: (1) HIF analysis to quantify the impact of heterogeneity on hydraulic fracturing; (2) DCH method for prediction of the production performance of hydraulically fractured wells; (3) economic evaluation of hydraulic fracturing projects based on RCF. Implementation of this workflow can be incorporated in reservoir model for fields in which hydraulic fracturing has been performed or is planned for some wells. This can produce time-efficient yet reasonable results in dynamic reservoir simulation.

- **Automation of data gathering and integration for hydraulic fracturing.** The primary workflow proposed in this study for integration of the outcomes of analyses form various disciplines involved in hydraulic fracturing can serve as a guideline for further work on automating the data gathering and integration process as the preceding step for reservoir simulation.

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