INVESTIGATION OF POST HYDRAULIC FRACTURING WELL CLEANUP PHYSICS IN THE CANA WOODFORD SHALE

by

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ABSTRACT

Hydraulic fracturing was first carried out in the 1940s and has gained popularity in current development of unconventional resources. Flowing back the fracturing fluids is critical to a frac job, and determining well cleanup characteristics using the flowback data can help improve frac design. It has become increasingly important as a result of the unique flowback profiles observed in some shale gas plays due to the unconventional formation characteristics.

Computer simulation is an efficient and effective way to tackle the problem. History matching can help reveal some mechanisms existent in the cleanup process. The Fracturing, Acidizing, Stimulation Technology (FAST) Consortium at Colorado School of Mines previously developed a numerical model for investigating the hydraulic fracturing process, cleanup, and relevant physics. It is a three-dimensional, gas-water, coupled fracture propagation-fluid flow simulator, which has the capability to handle commonly present damage mechanisms.

The overall goal of this research effort is to validate the model on real data and to investigate the dominant physics in well cleanup for the Cana Field, which produces from the Woodford Shale in Oklahoma.

To achieve this goal, first the early time delayed gas production was explained and modeled, and a simulation framework was established that included all three relevant damage mechanisms for a slickwater fractured well. Next, a series of sensitivity analysis of well cleanup to major reservoir, fracture, and operational variables was conducted; five of the Cana wells’ initial flowback data were history matched, specifically the first thirty days’ gas and water producing rates.

Reservoir matrix permeability, net pressure, Young’s modulus, and formation pressure gradient were found to have an impact on the gas producing curve’s shape, in different ways. Some moderately good matches were achieved, with the outcome of some unknown reservoir information being proposed using the corresponding inputs from the history matching study. It was
also concluded that extended shut-in durations after fracturing all the stages do not delay production in the overall situation.

The success of history matching will further knowledge of well cleanup characteristics in the Cana Field, enable the future usage of this tool in other hydraulically fractured gas wells, and help operators optimize the flowback operations. Future improvements can be achieved by further developing the current simulator so that it has the capability of optimizing its grids setting every time the user changes the inputs, which will result in better stability when the relative permeability setting is modified.
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DEDICATION

This work is dedicated to my mother, Dr. Lingying Ni, and my father, Mr. Honggang Lu.
CHAPTER 1

INTRODUCTION

In the last decade, the development of unconventional resources has increased greatly, including major shale gas plays in the United States. The resulting prosperity has led to unprecedented research interest in both academia and industry, regarding how to improve production and reserve amounts from these hydrocarbon reservoirs. In that “unconventional” context, hydraulic fracturing has become the most popular and maybe the most effective well stimulation technology.

The purpose of carrying out hydraulic fracturing (HF) treatment is to recover hydrocarbon fluids more efficiently and economically, by creating highly conductive paths in the formation near the wellbore, which has first been drilled and completed. One thing inherent in this process is that a huge amount of water needs to be pumped into the reservoir and at least a portion of the water is expected to flow back after the HF execution. This flowback stage is believed to directly represent the fracture cleanup situation and impacts the well’s long-term production performance. Furthermore, some unique characteristics of unconventional resources, for example a low initial water saturation, have displayed unique initial flowback profiles.

In this research, shale gas wells’ cleanup characteristics are studied and history matched with a numerical simulation model. This study evaluated the first thirty days of gas producing rates, time to initial gas production, and water rates observed from the Cana Field in Oklahoma. Through the process of history matching, potential insights can be gained, including: (1) appropriate reservoir property values for the Cana Woodford Shale, (2) the dominant damage mechanisms present in the Cana Field during and after the fracturing treatment, and (3) recommendations for the Cana Field development from the cleanup effectiveness standpoint.
1.1 Basic Information about the Study Area

The Cana Field is located in western Oklahoma and produces from the Cana Woodford Shale. The formation got its name because it is located in the Anadarko Basin (Figure 1.1) with the initial development program run in Canadian County (Figure 1.2). The location of some initial wells is shown in Figure 1.3. Production in the Anadarko Basin comes from Cambro-Ordovician through Permian strata. More specifically, the Cana Field is producing from the Upper Devonian Woodford Shale, with its production primarily consisting of gas, condensate, and natural gas liquids (Mitchell, 2012). Oklahoma is currently the fourth largest oil and gas producing state across North America, and the Woodford Shale has been known as the “flagship shale” in the state. It not only contains up to 10% total organic carbon (TOC) which makes it a great source rock, but also its characteristic of being siliceous makes the execution of hydraulic fracturing possible and efficient (Zou, 2014). It accounted for the majority of well completions in Oklahoma for more than half a century (Figure 1.4), and it still has much producing potential compared to some other shale gas plays, as shown in Figure 1.5.

The Cana Field is relatively young in that its first well was drilled in 2007, despite the fact that development activities for the Woodford Shale can be traced back to 1955. The whole field has around 250,000 acres and an estimated four trillion cubic feet of natural gas reserves. Devon Energy Corporation, which has about half of this field, has a long-term target production rate of 200 to 300 million cubic feet per day (Cameron, 2009). It was reported that the operators in this field had low cost of entry ($2,200/acre) and low royalty rates (20% average royalty burden). Devon’s net production rate in the third quarter of 2009 was around 53 million cubic feet per day (Jameson, 2009). Similar to other unconventional plays, horizontal drilling with multi-stage hydraulic fracturing has been adopted for the Cana Woodford Shale.
Figure 1.1: A map showing the location and boundaries of the Anadarko Basin (Mitchell, 2012).

Figure 1.2: Location of the Cana Field with the shale formation covering Blain, Caddo and Canadian Counties (Wood et al., 2011).
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Figure 1.4: An overview of all the well completions in shale formation in Oklahoma from the year of 1939 to 2013 (Cardott, 2013).
1.2 Objectives

The following discusses the research goal and the more specific thesis objectives.

**Research Goal**

To come up with a working model for the Cana Field development that helps understand the damage mechanisms in the Cana Field and how fracturing operation relates to well flow back, as well as helps improve hydraulic fracturing practices, by studying wells’ historical cleanup data.

**Thesis Objectives**

1. Review literature on cleanup modeling and history matching,

2. Understand the FAST Consortium in-house cleanup simulator by verifying results from case study runs for 0.05 md and 0.0005 md reservoir permeabilities (Charoenwongsa, 2011),
3. Using the validated simulator, investigate what mechanisms are potentially responsible for the early time delayed gas production present in the five slickwater fractured wells producing from the Woodford Shale in the Cana Field. If differences exist in the mechanisms between the five wells, explain these differences and the physical behaviors that are causing them,

4. Match the first 30 days gas and water production rates for the five wells using the simulator, especially studying whether the simulator could reproduce in the simulation outputs the time gap between opening the well to the flowback tank and gas starting to produce as observed in the field, and,

5. Evaluate the FAST Consortium in-house cleanup simulator.

1.3 Thesis Structure

This thesis is divided into five chapters. The first chapter introduces the general research goal and the more specific thesis objectives, along with the background of the research project as well as the basic information of the producing field under investigation.

The second chapter presents a comprehensive literature review on: 1) state-of-the-art hydraulically fractured well cleanup practice, 2) previous simulation studies on well cleanup, including the history matching work that has been done in the academia, 3) relevant damage mechanisms in slickwater fractured gas wells, 4) prior work done for the FAST Consortium simulator being used in this research, and 5) sources of data used by this study.

The third chapter talks about the methodology for conducting this research, which includes a general introduction to the simulator, and more specifically how it handles each flow impairment mechanism. The workflow of history matching is also covered.

The fourth chapter presents all the preparatory numerical analysis for history matching and the final matching results.
The last chapter presents important conclusions and recommendations based on the work documented in previous chapters.
CHAPTER 2

LITERATURE REVIEW

In this chapter, a comprehensive literature review on hydraulic fracturing and cleanup practices in the field, relevant flow impairment mechanisms in slickwater fractured wells, previous attempts at cleanup history matching, and prior work for the simulator used in this research are presented. In addition, sources of data for the Cana Field used in the simulations are discussed. The latest model proposed by Charoenwongsa (2011) is used as the foundation of this research.

2.1 Hydraulic Fracturing and Cleanup Practices

By means of pumping large volumes of fluid with added chemicals, laden with the propping agents (known as the “proppant”) into the reservoir (usually through several stages), the practice of hydraulic fracturing is performed. The exerted high pressure during this process tends to break down the rock, while creating cracks and fractures in the formation adjacent to the wellbore. After injection, the fractures gradually close and will finally be propped open by the proppant (Figure 2.1). It is the fractures that help channel the reservoir fluids out of their original places, conducting the fluids from the reservoir to the wellbore, and eventually up to the surface. Hydraulic fracturing also helps in terms of increasing the reservoir contact and production rate compared to the un-stimulated scenario (Vincent, 2011).

Just after the fracturing process and right before the production activities are initiated, a cleanup stage, or a flowback period is necessary. During this process, the fluids inside and near the fracture are expected to be extracted back out of the well. This is because the fracturing fluid, especially the gelled system, may cause damage to the fracture and to the adjacent matrix. During and after the pumping stage of a fracturing treatment, the fluid will contact the fracture face and to a certain extent, leak off into the reservoir matrix. In this process the fluid can interact chemically
with the formation and the fluids inside it, which would undermine the producing potential. For example, a gel filter cake will be formed on the inner face of the fracture as a result of the leak-off process, and serve as an additional flow resistance to the hydrocarbon fluids.

![Figure 2.1: Fracture will be held open by the proppant after pumping (Charoenwongsa, 2011).](image)

Additionally, the fluid with unbroken gel (i.e. gel that is not degraded back to the low-viscosity state) that stays inside the fracture serves as a multiphase obstacle on the flow path designed for hydrocarbons. For instance, oil-based fracturing fluids gelled with aluminum octoate chemicals are not easy to break down when pumped into a reservoir that produces a large amount of formation water (Porter, 1989). These fluids will occupy part of the porous space in the proppant pack and therefore impair hydrocarbons’ flow capacity. The above discussed scenarios are illustrated in Figure 2.2.

![Figure 2.2: Illustration of a type of formation damage inside and near the hydraulic fracture (Charoenwongsa, 2011).](image)
Thus, well cleanup or the flowback practice is designed for the purpose of preparing the well for production activities by recovering some of the fracturing and formation fluids (Crafton and Gunderson, 2007). The flowback behavior is of much importance and research interest, because that stage serves as a bridge linking the fracturing operation and the later production. On the one hand, flowback information can be used to infer the status and effectiveness of the fracturing treatment. Dehghanpour et al. (2014) came up with a method of using the measured salt concentration in the flowback fluids to characterize the complexity of the fracture architecture through aperture size distribution (ASD). Clarkson and Williams-Kovacs (2013) proposed that fracture half-length and permeability values can be obtained by analyzing early field flowback data (water/gas rates and flowing pressures within the first 48 hours after opening the well) using their analytical model. On the other hand, flowback information can be used to predict well long-term production performance, which is detailed in Section 2.2. On a less technical side, flowback has raised concern among the public, regarding appropriate disposal.

To get better knowledge of the exact recovery percentage of the fracturing fluids that have been pumped into the formation, some volumetric or chemical analysis for the flowback could be beneficial. One method is to use the load water recovery as an indicator, however, as long as there is formation water being produced, the results could be biased (Pope et al., 1996). For the fracturing practice which has gel pumped with the treatment, polymer concentration analyses have been used, either through colorimetric technique (Pope et al., 1996) or chromatography technique (Hoeman et al., 2011). The downside with this type of analysis is that polymer tends to self-concentrate as a result of the frac fluid leakoff, which makes the polymer concentration in flowback unreliable for calculating the cleanup efficiency, thus tracer method has been proposed as a newer solution (Asadi et al., 2008). Chemical tracer has the advantage of not being self-concentrate, and its application could be used to calculate the flowback percentage of each injected fluid segment, for example, in the case of multi-stage fracturing, each stage’s frac fluid flowback situation could be different and
In the field, several different cleanup methods have been proposed and put into practice. Controlled flowback was designed to minimize fracture-conductivity damage caused by proppant crushing and proppant flowback (Robinson et al., 1988). They suggested a practice of flowing the well on small chokes (i.e. slow flow rates) with gradual choke increases afterwards, instead of a large choke opened instantaneously. Obtaining closure stress values before the hydraulic fracturing treatment, as well as having the bottom-hole flowing pressure (BHFP) measured or calculated on a routine basis were part of the controlled flowback procedure. Another technique known as forced closure flowback was evaluated specifically for the purpose of reducing proppant flowback (Ely et al., 1990). They maintained a procedure of first flowing the well at a low rate for 30 minutes, after which the flowback rate would be increased. This method should be combined with high proppant concentrations and intense quality control on site to achieve success, as advised by Ely et al. In addition, reverse screenout flowback was proposed to achieve the goal of maximizing near-wellbore fracture conductivity (Barree and Mukherjee, 1995). They stressed the importance of allowing complete bridging of the proppant pack near the wellbore at the end of the treatment.

2.2 Previous Studies on Matrix and Fracture Cleanup after a Stimulation Treatment

As discussed, hydraulic fracturing has become an indispensable stimulation option in many situations, and cleanup is one necessary stage in the entire fracturing process. In reality, some hydraulically fractured wells do not perform up to expectations, and inefficient fracture and matrix cleanup has been considered one of the most important reasons. A sensitivity study has shown that gas production could be decreased due to the presence of fracture fluids downhole at early stages of production (Tannich, 1975). A field observation also indicated that when more polymer was recovered, higher production rates occurred (Pope et al., 1996). Some experimental work has been implemented where the conclusion was made that fracturing fluid residue decreases the fracture and matrix relative permeabilities for hydrocarbons, which results in poor production performance
In contrast, recently some operators in the Haynesville Field reported that some field data demonstrated a lower initial flowback percentage preceded better long-term production performance. A possible explanation given by Priestley (2012) is that the observed lower cleanup efficiency implied that a more complex underground fracture network was created and it held the part of the water which did not flowback, and that network increases reservoir contact and benefits long-term well productivity. Although significant water might stay in the formation, with the slickwater option, it does not “hurt” the formation as some other gelled systems do. For the observation in the Haynesville Field, Fan et al. (2010) proposed some similar but more detailed explanations that indicated that some water stays in the secondary fractures, which are filled with only water (as illustrated by the white waved lines in Figure 2.3) and do not provide a conductive path for the water to flow out due to lack of propping agents. Un-recovered water stays in the fractures instead of being imbibed into the shale matrix, otherwise imbibition indicates that the formation is water-wetting and then low load water recovery will impair gas flow on the rock surface, which in turn contradicts the field observation.

![Figure 2.3: A complex fracture network created during the fracturing treatment. Only the water inside the “fractures with proppant” will be flowed back during early production (Fan et al., 2010).](image)
Based on the discussions above, a similar flowback performance might indicate different or even opposite well producing potentials for the scenarios of conventional gel frac, slickwater frac used in water-wetting formations, and slickwater with non-water-wetting reservoirs. Thus, the author believes that the relationship between early well cleanup characteristics and long-term production is at least formation-dependent and operation-dependent, i.e. no universal correlation exists. For instance, it is also found in the literature that aggressive flowback led to different reservoir performances for water-producing and non-water-producing formations (Willberg et al., 1998).

To obtain improved cleanup efficiencies or better interpret certain cleanup behaviors observed in the field, many parametric studies have been conducted to look at only a single factor’s influence on cleanup: initial flow rate (Pope et al., 1996), fracture relative permeability (Sullivan et al., 2006), fracturing fluid’s viscosity (Penny et al., 1993), polymer yield stress (Ayoub et al., 2009), capillary pressure (Cawiezel et al., 2010) and gel filter cake dissolution (Gdanski and Bryant, 2012).

Some researchers chose to gain insights of cleanup physics by looking at results merely from numerical modeling (Wang et al., 2012) or from laboratory experiments (Barati et al., 2011). Others made an effort to refer to some real data from the field. Friedel et al. (2004) numerically modeled the cleanup stage and compared their results with real production data from a tight gas formation in Germany and Clarkson and Williams-Kovacs (2013) managed to match initial flowback data from wells completed in shale using their analytical model. But both of these studies only examined the very early flowback data, ranging from the first 48 hours to the first four to five days. In this work, field data of up to the first month’s flowback are investigated and matched using a numerical simulator, in order to gain more understanding of the cleanup process. A series of parametric sensitivity analysis are also completed to give deeper insights into various factors’ role in the well cleanup context.
2.3 Relevant Damage Mechanisms in Slickwater Fractured Gas Wells

During the stimulation and production stage for a hydraulically fractured well, several damage mechanisms will come into play. Currently slickwater is often chosen when stimulating shale and tight gas reservoirs, which means there is no linear or cross-linked polymer gel pumped with the treatment fluids and the addition of friction reducer is sometimes a must. It has the advantages of getting rid of polymer-related damage mechanisms, and of being more affordable than conventional gel treatment (Kazakov, 2010). The following discusses the common types of damage related to slickwater fractured gas wells, which are of research interest within this thesis and are detailed in Section 2.5.1.

2.3.1 Compaction Effects

The compaction effects studied here apply to both proppant pack (propped fracture) and reservoir matrix. For the proppant compaction, it describes situations when the closure stress (defined as minimum horizontal stress minus fracture pressure in this research) is large at fracture closure (Charoenwongsa, 2011), and it yields the result that fracture permeability will be impaired compared to the ideal situation.

Regarding the reservoir compaction, it means that as hydrocarbon fluids are being produced, the reservoir matrix experiences a compacting process which makes its permeability decrease to a certain extent. The overburden pressure above the whole producing formation is exerted on both the reservoir fluids and the rock matrix, therefore a larger portion of pressure will be distributed to the matrix as the fluids pressure drops as production advances. Then the “pressurized” matrix’s permeability is lowered. The details of how compactions are numerically treated are covered in Section 3.1.1.
2.3.2 Capillary End Effect

Capillary end effect (sometimes referred to as “water blockage”), in the context of fractured gas well cleanup, describes situations where a certain amount of water is trapped in the vicinity of the fracture and causes additional resistance to gas flow during production. This effect could last quite long, even into the late production stage.

As time passes in the production stage, gas displaces water from the matrix into the fracture; however, finally \((t \to \infty)\) for the matrix adjacent to the fracture face, there still exists a water saturation profile where the saturation values are higher than that of the residual water saturation (illustrated in Figure 2.4). Specifically the water buildup on the matrix-fracture interface (as indicated by the blue dot in the figure) is caused by the sudden change of capillary pressure from the matrix to the fracture, i.e. the capillary pressure is much smaller inside the fracture than in the matrix. Such water trapping will impede gas production, and is modeled as a damage mechanism in this research. The details of the numerical treatment are presented in Section 3.1.2.

![Figure 2.4](image)

Figure 2.4: Impact of capillary end effect on the water saturation profiles in the production stage, where \(t = \) production time, \(t_0 < t_1 < t_2 < t_3 < \infty\), \(Sw = \) water saturation, \(Swr = \) residual water saturation, and \(Sgt = \) trapped gas saturation (Charoenwongsa, 2011).

2.3.3 Non-Darcy Flow

Non-Darcy gas flow effect is present in some of the hydraulically fractured gas wells,
especially for those with higher rates. Originally according to Darcy’s law, the pressure gradient is linearly proportional to the fluid velocity for fluid flow in porous media. The one dimensional expression (Zeng and Grigg, 2006) is shown as:

\[- \frac{dp}{dx} = \frac{\mu v}{k}\]  \hspace{1cm} (2.1)

where,

- \(p\) = pressure
- \(\mu\) = viscosity
- \(v\) = velocity
- \(k\) = absolute permeability

In situations of turbulent flow or high velocity flow, which could be typically observed in fractured gas wells especially in and near the high conductivity proppant pack, the above mentioned linear correlation does not reflect the real flow field any more. The Darcy equation can be corrected using a coefficient \(\beta\) (Forchheimer, 1901):

\[- \frac{dp}{dx} = \frac{\mu v}{k} + \beta \rho v^2\]  \hspace{1cm} (2.2)

where,

- \(p\) = pressure
- \(\mu\) = viscosity
- \(v\) = velocity
- \(k\) = absolute permeability
- \(\rho\) = density of the fluid

There have been some empirical correlations put forward for the non-Darcy flow coefficient, as shown in Figure 2.5.
2.4 Prior Work

Wills (2009) presented a two-phase, 3-D, finite difference numerical model to investigate the hydraulic fracture cleanup processes. Unlike other previous numerical models, his work captures the dynamic fracture propagation process instead of placing a stationary, pre-determined fracture into the model for the later flow simulations. Putthaworapoom (2010) modified Wills’ model to improve its computational efficiency. He also did a comprehensive sensitivity analysis for a series of reservoir properties and operational variables. Charoenwongsa (2011) further improved the model and came up with an 3-D, coupled fracture propagation-fluid flow simulator whose new features include the capability to model capillary end effect, non-Darcy gas flow in both the fracture and the formation, polymer damage effects, and compaction effects. Using this tool, some example simulation results for the first thirty days’ gas and water production rates for a 0.0005 md reservoir are shown in Figures 2.6 and 2.7. The effects of multiphase flow (MP), capillary end
(CE), as well as non-Darcy flow (ND) on cleanup were taken into consideration and simulated for a single hydraulic fracture.

Figure 2.6: Simulated first 30 days of gas production for a single fracture. This figure shows the effects of capillary end (CE) and non-Darcy flow (ND) on the post-frac gas production in the multiphase (MP) scenario for a 0.0005 md reservoir.

Regardless of the significance of all the previous efforts, it is more meaningful and valuable to utilize this tool with application to real field data. Successful validation of the model and the corresponding workflow on real data will give confidence for solving real problems. Directions are also proposed for improving this simulator for later usage in the field and for commercialization if possible. The use of this cleanup model in the context of the Cana Woodford Shale gas wells is demonstrated in this thesis.
Figure 2.7: Simulated first 30 days of water production for a single fracture. Effects of capillary end (CE) and non-Darcy flow (ND) do not have much impact on the post-frac water production in the multiphase (MP) scenario for a 0.0005 md reservoir.

2.5 Sources of Data

In this research, numerical analysis of matrix and hydraulic fracture cleanup is conducted based on the development and production activities of the Cana Woodford Shale formation. As discussed earlier, the Cana Field in Oklahoma is relatively young compared to some other shale plays, much production activities beginning in 2007. Therefore, there has not been much literature to date on the details of the Cana Field. Most of the fundamental information necessary for the modeling work is from an operator in that field.

2.5.1 Field Data

Five wells provided by Devon Energy Corporation from the Cana Field in Oklahoma are being analyzed, all of which are multi-fractured horizontal wells (MFHW). They were all fractured with slickwater fluid. This means neither linear gel nor cross-linked polymer was added into the
treatment fluids. The original information consists of a completion database and a series of flowback reports (cleanup data). The former contains some basic well information (e.g. location and dates), completion parameters (e.g. stage and cluster spacings, perforation details, etc.), and hydraulic fracturing treatment information (e.g. pumping rate, injection fluid volume, and placed proppant volume).

For the flowback reports, each of the five wells was recorded for its initial flow back rates of water, oil, and gas. The readings were taken at hourly frequencies, recorded from the beginning of flowing back the well, to approximately the end of the first thirty days. Example plots of one well’s gas and water production rates are shown in Figures 2.8 and Figure 2.9, respectively. Close to 200 parameters along with their values are included in the original databases for each well, and those parameters which are necessary for the simulation studies are discussed in detail in the following chapters.

Figure 2.8: First 30 days’ gas producing profile for a well in the Cana Field.
Along with the two types of database, one summary report for the routine crushed core analyses was provided by Devon as well. The summary report consists of results from testing both the as-received (A-R) samples and the vacuum dried samples (at a temperature of 212°F). Some measured values for porosity and permeability from testing dried samples are shown in Table 2.1.

2.5.2 General Information for the Cana Woodford Shale

Since the drilling of the Cana wells beginning in 2007, the operators have gone through many drilling challenges such as downhole BHA vibrations (Chesher et al., 2010), and a trial-and-error process of optimizing stimulation treatment (Potts et al., 2013). Thus, there has been some variance regarding the completion and stimulation specifications for the five wells studied in this research.

Grieser and Talley (2012) reported that the gross pay thickness ranges from 175 to 331 feet. Reservoir porosity is 4% to 7%. Initial water saturation is around 25%, and 0.68 psi/ft is an appropriate assumed value for reservoir pressure gradient and reservoir permeability has a value...
Table 2.1: Lab Measured Porosity and Permeability Values from a Report Summary of Routine Crushed Core Analyses Results for the Cana Woodford Shale (Frank, 2013b)

<table>
<thead>
<tr>
<th>Sample ID</th>
<th>Dry Helium Porosity (% of Bulk Volume)</th>
<th>Dry Pressure Decay Permeability (md)</th>
</tr>
</thead>
<tbody>
<tr>
<td>1</td>
<td>8.2</td>
<td>1.89E-04</td>
</tr>
<tr>
<td>2</td>
<td>8.3</td>
<td>2.19E-04</td>
</tr>
<tr>
<td>3</td>
<td>7.2</td>
<td>8.81E-05</td>
</tr>
<tr>
<td>4</td>
<td>9.2</td>
<td>6.00E-04</td>
</tr>
<tr>
<td>5</td>
<td>7.8</td>
<td>1.51E-04</td>
</tr>
<tr>
<td>6</td>
<td>7.3</td>
<td>1.67E-04</td>
</tr>
<tr>
<td>7</td>
<td>7.6</td>
<td>1.72E-04</td>
</tr>
<tr>
<td>8</td>
<td>5.9</td>
<td>6.88E-05</td>
</tr>
<tr>
<td>9</td>
<td>7.1</td>
<td>2.34E-04</td>
</tr>
<tr>
<td>10</td>
<td>4.8</td>
<td>6.64E-04</td>
</tr>
<tr>
<td>11</td>
<td>8.2</td>
<td>4.07E-04</td>
</tr>
<tr>
<td>12</td>
<td>7.2</td>
<td>2.08E-04</td>
</tr>
<tr>
<td>13</td>
<td>7.7</td>
<td>2.15E-04</td>
</tr>
<tr>
<td>14</td>
<td>8.8</td>
<td>4.88E-04</td>
</tr>
<tr>
<td>15</td>
<td>7.8</td>
<td>2.23E-04</td>
</tr>
<tr>
<td>16</td>
<td>5.9</td>
<td>1.77E-04</td>
</tr>
<tr>
<td>17</td>
<td>6.6</td>
<td>3.11E-04</td>
</tr>
<tr>
<td>18</td>
<td>5.6</td>
<td>8.86E-05</td>
</tr>
<tr>
<td>19</td>
<td>5.4</td>
<td>4.08E-05</td>
</tr>
<tr>
<td>20</td>
<td>1.4</td>
<td>5.13E-05</td>
</tr>
<tr>
<td><strong>Average</strong></td>
<td>6.9</td>
<td><strong>2.38E-04</strong></td>
</tr>
</tbody>
</table>

range from 0.0003md to 0.0009md. Through nanoindentation measurements Kumar et al. (2012) concluded that reasonable Young’s modulus values for the Woodford Shale have a range from 23 GPa (3.34E+06 psi) to 79 GPa (1.15E+07 psi). It has been reported that 708 Rankine degree is a good estimation for shale gas reservoir temperature (Zhang et al., 2013) and the shale formation water’s salinity has a range of around 188,000 ppm to 254,000 ppm (Miller and Cluff, 2010). These values along with those extracted from the lab report mentioned in the above section served as the references for the input data for the simulation studies detailed in Chapter 4.
CHAPTER 3

METHODOLOGY

This chapter discusses the methodology used in this research. First an introduction to the FAST Consortium in-house cleanup simulator is presented, including the details of the numerical treatment for the three slickwater-frac related damage mechanisms, and then the procedures for carrying out the history matching are demonstrated.

3.1 Numerical Simulator

In this work, an in-house hydraulic fracturing and cleanup simulator was selected for the proposed numerical studies. It is a 3-D, water-gas, coupled fracture propagation-fluid flow simulation tool developed by Charoenwongsa (2011) within the Fracturing, Acidizing, Stimulation Technology (FAST) Consortium at Colorado School of Mines. One of this simulator’s unique features is its treatment of polymer gel as a chemical component in the aqueous phase instead of as another phase with high viscosity (Charoenwongsa et al., 2013). It provides the capability of furthering knowledge in formation damages and gel-cleanup mechanisms, in that relevant physics and several dominant damage mechanisms have been incorporated into the simulator. For instance, multiphase flow, capillary end effects, polymer damages, reservoir and proppant pack compactions, as well as shut-in behavior following the treatment can be modeled within the simulator. Polymer damages can be further broken down into gel filter cake’s formation, polymer adsorption onto the matrix, and non-Newtonian flow behavior exhibited by the residual fracturing gel, all of which can be simulated altogether or individually.

The current simulator is written in MATLAB. The version used in this research does not have a graphical user interface. The user must modify a data file (MATLAB M File) for changing the inputs, and after the simulation is done some output files will be generated, which may be imported
to a post-processing software (e.g. Microsoft Excel or OriginPro) for visualization of the results.

This simulator was designed to perform numerical modeling on a quarter of the whole producing system with a rectangular reservoir, plus a vertical fracture with two symmetrical wings located at the center. A fracture model and a geomechanics-flow model were developed, coupled, and integrated into the simulator. The fracture model adopted by this simulator is a PKN (Perkin, Kern and Nordgren) fracture, whose inherent assumption is that the vertical fracture is fully contained within the pay zone with a constant height. The geomechanics and flow model was developed based on the governing equations defining physical laws and constitutive laws. The two parts are coupled through the fracture face displacement and the leakoff (Figure 3.1). Detailed mathematical formulations and major assumptions of the model can be seen in Charoenwongsa (2011).

![Figure 3.1: Coupling between the fracture model and the geomechanics-flow model (Charoenwongsa, 2011).](image)

The following discusses how the simulator handles each relevant damage mechanism illustrated in Section 2.3.
3.1.1 Compaction Effects

As discussed in Section 2.3.1, compaction effects apply to both the reservoir matrix and the hydraulic fracture. For the fracture part, the relation of closure permeability (i.e. the permeability at fracture closure) to closure stress used in this research is expressed mathematically in Equation 3.1 (Charoenwongsa, 2011) and is plotted as Figure 3.2. As the closure stress increases, the fracture closure permeability will be lowered and the compaction effect is modeled.

\[
k_p = -2.0736979167 \times 10^{-13} \times \sigma_c^4 + 4.4422291667 \times 10^{-9} \times \sigma_c^3 - 2.8210520833 \times 10^{-5} \times \sigma_c^2 + 1.2521583334 \times 10^{-2} \times \sigma_c + 3.11366 \times 10^2
\] (3.1)

where,

- \(k_p\) = permeability of proppant pack at closure, Darcy
- \(\sigma_c\) = closure stress (defined as \(\sigma_c = \sigma_{h, \text{min}} - p_f\)), psi
- \(\sigma_{h, \text{min}}\) = minimum horizontal stress, psi
- \(p_f\) = fracture pressure, psi

Figure 3.2: The relation of propped fracture permeability to closure stress used in this research.
The way the reservoir compaction effect is handled in the simulator is that a retained permeability factor (dimensionless) is applied to the input value of the original matrix permeability during production simulation. The product of the factor and the initial permeability input is used to update the permeability’s value. The retained permeability factor is calculated using Equation 3.2 (Charoenwongsa, 2011). One example relation of retained matrix permeability (in fraction) to net stress (defined as minimum horizontal stress less reservoir fluids pressure) is shown in Figure 3.3.

\[
f_{pr} = \frac{6.1457645160 \times 10^{-16} \times \sigma_{ni}^4 - 1.3180640733 \times 10^{-11} \times \sigma_{ni}^3}{6.1457645160 \times 10^{-16} \times \sigma_{ni}^4 - 1.3180640733 \times 10^{-11} \times \sigma_{ni}^3 + 1.0970579092 \times 10^{-7} \times \sigma_{ni}^2 - 4.767303070 \times 10^{-4} \times \sigma_{ni} + 1.2065958825}
\]

(3.2)

where,

- \( f_{pr} \) = retained permeability factor, fraction
- \( \sigma_{ni} \) = initial net stress (defined as \( \sigma_{ni} = \sigma_{h,min} - p_i \)), psi
- \( \sigma_{h,min} \) = minimum horizontal stress, psi
- \( p_i \) = initial reservoir pressure, psi
- \( \sigma_n \) = net stress at one certain time point during production (defined as \( \sigma_n = \sigma_{h,min} - p_r \)), psi
- \( p_r \) = average reservoir pressure at one certain time point during production, psi

3.1.2 Capillary End Effect

Capillary end effect is modeled as the result of the combined effects of relative permeability and capillary pressure issues. As discussed in Section 2.3.2, at the fracture face, water phase will build up to a certain saturation, and until reaching that “critical” saturation value, water cannot flow out into the fracture. The “critical” or maximum water saturation will be reached when the capillary pressure drops to zero.
Figure 3.3: One example relation of fraction of retained matrix permeability to net stress (Charoenwongsa, 2011).

To mimic this mechanism during well production, the simulator lets the reservoir grid blocks adjacent to the fracture have a different water relative permeability setting, as shown by the blue lines in Figure 3.4. This allows the process to be modeled of water flowing into the near-fracture region and being built up to the critical saturation value.

3.1.3 Non-Darcy Flow

Non-Darcy gas flow is captured for both the hydraulic fracture and the reservoir matrix. The non-Darcy (ND) velocity of the gas phase $\vec{v}_{ND}$ is explicitly calculated from the equation below (Charoenwongsa, 2011):

$$\vec{v}_{ND} = -\frac{k k_f}{\mu} \left[ \frac{1}{1 + R e_{ND}} \right] (\nabla p - \gamma \nabla D)$$

(3.3)

where,

$$R e_{ND} = \frac{1}{2} \left[ \sqrt{1 + 4 R e} - 1 \right]$$

$$R e = \frac{k k_f}{\mu} \rho \beta |\vec{v}_D|$$
Figure 3.4: Capillary pressure and relative permeability curves for the reservoir matrix, where the blue solid lines are for the reservoir grid blocks adjacent to the fracture, the black dashed curve is for the reservoir not in the vicinity of the fracture, and one single gas relative permeability curve applies to the whole reservoir matrix (Charoenwongsa, 2011).

\[ \vec{v}_N = -k \frac{k_{pr}}{\mu} (\nabla p - \gamma \nabla D) \]

\( \vec{v}_N \) = Darcy velocity of the gas phase

\( \beta \) = non-Darcy flow coefficient of the gas phase

\( k \) = absolute permeability of the porous media

\( k_{pr} \) = relative permeability of the gas phase

\( \mu \) = viscosity of the gas phase

\( p \) = pressure of the gas phase

\( \gamma \) = density times gravitational acceleration for the gas phase

\( D \) = depth

\( \rho \) = density of the gas phase

Equations 3.4 (Frederick Jr and Graves, 1994) and 3.5 (Friedel, 2004) are used to calculate the non-Darcy flow coefficient \( \beta \) for the matrix and the fracture, respectively (Charoenwongsa,
2011):

\[
\beta_m = 1.98 \times 10^{11} k_m^{-1.64}
\]

\[
\beta_f = 4.11 \times 10^9 k_f^{-1.11}
\]

(3.4) (3.5)

where,

\[ k = \text{absolute permeability of the porous media} \]

subscripts

\[ m = \text{matrix} \]

\[ f = \text{fracture} \]

3.2 History Matching

In order to improve understanding of the well cleanup process in the Cana Field, the method of using simulation results to history match the field data is adopted in this research. Basically, if certain consistencies can be obtained across the sets of input values for history matching the studied wells, the input should at least partly reflect the real field situation. The current simulator models the injection, shut-in, and production stages for a single vertical hydraulic fracture under a normal flow. However, the field data obtained for this research is all overall flowback data (i.e. information for each stage’s flow rate or volume is not available) from multi-stage fractured wells with basic completion information shown in Table 3.1. Therefore, an approximate approach with assumptions is adopted here. It was assumed that for each Cana well, there was one vertical hydraulic fracture effectively stimulated and producing every two perforation clusters, the total injection volume was evenly distributed to each and every fracture, and proppant placement was uniform along every fracture. The interference between adjacent fractures (for example the stress shadow effect) was ignored. All the user inputs (e.g. injection volume) and field production data needed to be averaged to the values for every two perf clusters, i.e. for each single fracture. In the case of the number of clusters being odd, a smaller fracture which delivers half the amount of gas compared to a normal fracture is assumed to be created for the last cluster. Finally the task was to
check whether the modeling results from each run could be matched with the well production data, after they were averaged for each hydraulic fracture.

Table 3.1: Basic Completion Information for the Five Cana Wells

<table>
<thead>
<tr>
<th>Well</th>
<th>Stage</th>
<th>Number of Perforation Clusters</th>
<th>Cluster Spacing, ft</th>
<th>Average Fluid Volume per Cluster, gal</th>
</tr>
</thead>
<tbody>
<tr>
<td>A</td>
<td>8</td>
<td>31</td>
<td>126</td>
<td>202,832</td>
</tr>
<tr>
<td>B</td>
<td>9</td>
<td>37</td>
<td>97</td>
<td>188,030</td>
</tr>
<tr>
<td>C</td>
<td>9</td>
<td>36</td>
<td>105</td>
<td>197,784</td>
</tr>
<tr>
<td>D</td>
<td>9</td>
<td>35</td>
<td>113</td>
<td>191,519</td>
</tr>
<tr>
<td>E</td>
<td>9</td>
<td>36</td>
<td>121</td>
<td>195,215</td>
</tr>
</tbody>
</table>

The target was to match the first thirty days’ gas and water flowback rates for the five slickwater wells. During this process, the values of certain parameters are adjusted until decent matches between the model output and the measured data are achieved. The foremost guideline when trying to achieve matches is to make sure all of the inputs are as realistic and reasonable as possible. More specifically, the operational data in the simulation inputs are exactly the same as that from the field (fixed), and for other reservoir and fracture related inputs (non-fixed), efforts have been made to ensure they either correspond to the reference values from the lab report or to those from the literature, as presented in Chapter 2.

Although the five wells studied have certain variances from the operational perspective and some heterogeneity of the formation characteristics is expected, part of the simulation inputs are the same for all wells, for instance, the relative permeability curves for the matrix and fracture, which are discussed in more detail in Chapter 4. In addition, the major required inputs (most of them will be different on a well-to-well basis) are listed below:

1. A customized grid file:

   The number and size of the grids in the directions of fracture length, width, and height shall be modified by the user. Making the grids near the fracture tip finer often improved the stability of the models.
Specifying a new grid file will affect fracture propagation in simulations and thus will change the final fracture dimensions. Since the simulator uses a PKN (Perkin, Kern and Nordgren) fracture model (Charoenwongsa, 2011), the fracture height is equal to the reservoir pay thickness.

2. Included damage mechanism(s):

One or several of the three mechanisms (capillary end effect, non-Darcy flow, and compaction effects) could be present in reality and be included in the simulations. Different combinations of these mechanisms and how those options affect the modeling results are discussed in Chapter 4.

3. Reservoir data:

Important variables in the reservoir section include formation pressure gradient (psi/ft), reservoir depth (ft, which reads from the True Vertical Depth in the completion database), reservoir matrix porosity (dimensionless), reservoir matrix permeability (md), Young's modulus (psi), and net pressure (psi, defined as injection pressure less minimum horizontal stress).

4. Fracture data:

Key variables to be input include fracture porosity (dimensionless) and permeability (md) at closure.

5. Operational data:

As discussed above, the inputs for this part are from the field database. Main parameters consist of shut-in duration before production activities (days), injection rate (bbl/day), and total injection volume (bbl).

6. Bottom-hole pressure (BHP) data:

The BHP is assumed to be equal to the fracture pressure in this simulator and its decline after the well being put on production can be controlled by the user through two parameters: BHP decline rate (dimensionless) and a minimum or final BHP value (psi).
Similar to the example BHP profile shown in Figure 3.5, the BHP in the model will be exponentially interpolated between the initial reservoir pressure and the minimum BHP value (Charoenwongsa, 2011). The input parameter BHP decline rate is a coefficient in the exponential function and is used to modify the pressure changing profile.

Figure 3.5: An example BHP decline profile (Charoenwongsa, 2011).
CHAPTER 4
NUMERICAL STUDIES

This chapter presents the details and results of numerical modeling and history matching for five subject wells in the Cana Field.

4.1 Overview and the Universal Input

As described within the thesis objectives, the previous case study runs (Charoenwongsa, 2011) for reservoir permeabilities of 0.05 md and 0.0005 md were verified to ensure the completeness and effectiveness of the source code. After that, a series of simulation studies were carried out with the end goal of achieving good matches between simulation outputs and the real production data.

Before delving into finding out the most suitable set of inputs for modeling each specific Cana well, three types of analysis, also with the aid of the simulator, had to be completed. First and foremost, it was necessary to explain the early time gas delay behavior observed in the field, and analyze the sensitivity of the cleanup process to the different combinations of damage mechanisms, and to the reservoir and fracture variables – all of which will be discussed in the next three consecutive sections before coming to Section 4.5 which covers the results of history matching.

Despite the variance in the operational specifications (treatment schedule, job size, etc.) across the five wells, some variables’ values were believed to differ very little from well to well, thus there is a universal input component that applies to each well during history matching and during all the fundamental numerical experiments conducted.

4.1.1 Base Input Data

The basic input data are presented in Table 4.1.
Table 4.1: Base Input Data for All the Simulations in this Thesis

<table>
<thead>
<tr>
<th>Reservoir Data</th>
<th></th>
</tr>
</thead>
<tbody>
<tr>
<td>Initial reservoir temperature (F)</td>
<td>249</td>
</tr>
<tr>
<td>Initial water saturation (-)</td>
<td>0.45</td>
</tr>
<tr>
<td>Pore compressibility (psi⁻¹)</td>
<td>3.00E-06</td>
</tr>
<tr>
<td>Rock density (lb_m/ft³)</td>
<td>170</td>
</tr>
<tr>
<td>Poisson's ratio (-)</td>
<td>0.15</td>
</tr>
<tr>
<td>Specific gravity of gas (-)</td>
<td>0.65</td>
</tr>
<tr>
<td>Salinity of formation water (ppm)</td>
<td>200,000</td>
</tr>
<tr>
<td>Overburden gradient (psi/ft)</td>
<td>1</td>
</tr>
</tbody>
</table>

| Fracture Data                                   |            |
| Minimum fracture width (fraction of the maximum width) | 0.5        |

| Operational Data                                |            |
| Injection fluid temperature (F)                 | 151        |
| Salinity of injected water (ppm)                | 20,000     |
| Proppant density (lb_m/ft³)                     | 110        |
| Polymer concentration of slickwater (ppm)       | 0          |

4.1.2 Relative Permeability Curves

The default gas-water relative permeability settings are shown in Figures 4.1 and 4.2. These curves were used for this research as well. They were originally from experimental results from literature and Stim-Lab (Charoenwongsa, 2011). Note that in the case of capillary end effect being turned on in the simulations, the reservoir matrix adjacent to the fracture has a water relative permeability curve (Figure 3.4) which is different from that in Figure 4.1.

4.1.3 Capillary Pressure Curves

In this research the capillary pressure inside the fracture was treated as zero (in some real cases the value may not be small enough to be ignored). The matrix part curves are shown in Figure 4.3. Note that only the curve for 0.0005 md reservoir permeability was adopted in this research even though the permeability input might not be exactly 0.0005 md in some simulation cases. The
capillary pressure equals zero when the water saturation reaches 85%.

Figure 4.1: Relative permeability curves for the reservoir matrix (Charoenwongsa, 2011).

Figure 4.2: Relative permeability curves for the hydraulic fracture (Charoenwongsa, 2011).
4.1.4 Proppant Schedule

The treatment information (e.g. injection volumes and rates) was provided in full detail (Frank, 2013a) except the proppant and fluids schedule. The proppant schedule used as simulation input in this thesis is presented in Figure 4.4. The proppant concentration reached 1.25 pounds per gallon (ppg) towards the end of the injection stage.

4.2 Investigation of the Early Time Delayed Gas Production Observed in the Cana Field

As stated in the thesis objectives, one problem to be solved was trying to explain the early time delayed gas production behavior, i.e. there existed several days’ time gap between opening the well and initial gas production. This behavior is illustrated by Figure 4.5. When considering Well D, gas does not start flowing back from the reservoir up the well until about eight days after the operator opened the well (time zero in the graph) to the flowback tank.
This post-frac gas delay varies from approximately four to eight days across the five wells, whereas water started flowing back as soon as the well was opened, i.e. at time zero on the same time scale. Typical gas producing profiles in previous simulation case studies (Charoenwongsa, 2011) are shown in Figure 4.6, where gas produces quickly compared to real situations in the Cana Field.

It was discovered that for the original case study runs, the dynamic fracture closure process was not captured very well, whereas slow closure phenomena usually exist for unconventional reservoirs (Figure 4.7). Physically, after the injection stage, the fracture first gradually closes to its minimum width and will be continuously compacting as fracture pressure drops. During the closing and compacting processes, water inside the fracture can be flowed back (i.e. fracture cleanup). After that, formation gas will be produced. Thus, if the fracture closes slowly, it will push back the gas production to a later date. In other words, in the Cana Field, when the wells were...
opened, the fractures had not achieved closure yet and gas in the reservoir would not immediately start being produced back.

![Graph showing gas rate over time](image)

**Figure 4.5: Early time delayed gas production for Well D.**

The current simulator models three stages: injection, shut-in, and production. In those original case runs, after the injection, the fracture would be fully closed within a short period of time (usually within the fixed one day shut-in period), and the production is simulated thereafter. In the field it could take 100 hours for the fracture to close in a 0.005md reservoir (Nojabaei and Kabir, 2012). In the simulations for the Cana wells in this research, the permeability values used as input were from 0.00010 md to 0.00065 md, which means that it could take much longer than 100 hours for the closure to happen.
Figure 4.6: Some gas producing profile examples from (Charoenwongsa, 2011), where MP = multiphase flow base case, CE = capillary end effect, ND = non-Darcy flow effect, PD = polymer damages, and CP = compaction effects.

Figure 4.7: It takes a much longer time for the hydraulic fracture to achieve closure for lower reservoir permeability situations (Nojabaei and Kabir, 2012).
One possible reason which could account for the slow fracture closure is that immediately after the injection stage, the pressure within the fracture is very high and declines slowly, which keeps the fracture open for a certain amount of time. This explanation can be modeled through the simulator. The bottom-hole pressure (BHP) is assumed to equal fracture pressure within the simulator, and its decline profile is adjustable through two parameters: a coefficient in the exponential function and the final minimum BHP value, as discussed in Section 3.2. Thus the change of fracture pressure can be modeled through adjusting the BHP as an equivalent in the simulator. The following discusses the effects of changing these two variables’ values, the results of which will be compared to the results presented in Figure 4.6.

The corresponding inputs and results are listed in Table 4.2. Please note that for Run #2, #3, and #4, all other inputs except those specified in the table are exactly the same as in Run #1. Those results were shown previously as Figure 4.6, in which negative values for the decline coefficient indicate that the BHP is decreasing, and the greater its absolute values, the faster BHP drops toward its final value.

<table>
<thead>
<tr>
<th>Run #</th>
<th>Decline coefficient (-)</th>
<th>Final BHP (psi)</th>
<th>Results shown in</th>
</tr>
</thead>
<tbody>
<tr>
<td>1</td>
<td>-5</td>
<td>1000</td>
<td>Figure 4.6</td>
</tr>
<tr>
<td>2</td>
<td>-0.1</td>
<td>1000</td>
<td>Figure 4.8</td>
</tr>
<tr>
<td>3</td>
<td>-0.05</td>
<td>1000</td>
<td>Figure 4.9</td>
</tr>
<tr>
<td>4</td>
<td>-5</td>
<td>2500</td>
<td>Figure 4.10</td>
</tr>
</tbody>
</table>

As indicated by the figures above, increasing the BHP decline coefficient results in the fracture pressure maintaining a higher value for a longer period, which helps delay the fracture closure and thus postpones the gas production. Simply increasing the final BHP value does not help much in
Figure 4.8: Simulation results for gas production using a BHP decline coefficient of -0.1.

terms of making the time gap longer, while it does help lower the gas producing rates by reducing the pressure drawdown (reservoir pressure minus BHP). These gained insights helped direct the history matching work, which is detailed in Section 4.5.

4.3 Sensitivity to Damage Mechanisms

As discussed in Chapter 3, the simulator chosen for this research has the ability to include damage mechanisms in its flow simulations in four categories: capillary end effects (CE), non-Darcy flow (ND), compaction effects (CP), and polymer damages. Specifically, compaction effects are further broken down into proppant pack and reservoir matrix compactions. Polymer damages are sub-divided into adsorption, filter cake, and non-Newtonian rheology. All these are optional “modules” that can be added to the base multiphase flow situation (MP), which is part of the
Figure 4.9: Simulation results for gas production using a BHP decline coefficient of -0.05.

Figure 4.10: Simulation results for gas production using a final BHP value of 2500 psi.
“conventional features” of this numerical model and has been validated with analytical solutions (Charoenwongsa, 2011). Basically, the conventional or base model captures an ideal production situation where a homogeneous and isotropic reservoir matrix and a bi-wing vertical hydraulic fracture are included for the two-phase (gas and water) flow simulation.

To have an idea about how the MP case compares and contrasts to real gas production data, one run without any damage mechanisms included along with field data of Well D is plotted in Figure 4.11.

As seen from Figure 4.11, the base numerical model which excluded all flow impairment possibilities not only overestimates the gas producing rates throughout the whole thirty day period, but it also gives an inaccurate climbing and declining profile compared to a relatively flattened one observed in the field data. Considering the unsatisfactory results generated by the model without any damage mechanisms as well as the fact that slickwater (almost only fresh water) was chosen as the stimulation method for the studied wells, capillary end effects (CE), non-Darcy flow (ND) and compaction effects (CP) are relevant and should be taken into consideration when conducting history matching.

Treating the ideal case (MP) as a base, one or several of the three damage options could be switched on to reflect the field situation. There are eight different possible combinations, as shown in Table 4.3.

<table>
<thead>
<tr>
<th>1. MP</th>
<th>5. MP + CE + ND</th>
</tr>
</thead>
<tbody>
<tr>
<td>2. MP + CE</td>
<td>6. MP + CE + CP</td>
</tr>
<tr>
<td>3. MP + ND</td>
<td>7. MP + ND + CP</td>
</tr>
<tr>
<td>4. MP + CP</td>
<td>8. MP + CE + ND + CP</td>
</tr>
</tbody>
</table>

Including all eight possible combinations not only extends previous studies (Charoenwongsa, 2011) which only considered four options, but is more appropriate for history matching when looking for the best possible answer. Figures 4.12 and 4.13 show all options compared to the field data for Well D.
Figures 4.12 and 4.13 show that including all three damage mechanisms (CE, ND, and CP) reduced gas rates to the field data region, and also created a profile consistent with the flattened shape from about the 15th day. Other benefits included not having instability issues like outputting the “jagged” curves among another four options for this well. Alternatively, different combinations of the damage mechanisms did not have much impact on the water production profile as presented in Figure 4.13, which is consistent with previous observations and study results for lower permeability scenarios (~0.0005 md), damage mechanisms have little influence on the water flowback from a fractured gas well (Charoenwongsa, 2011). Given all the above considerations, the base model with all three relevant damage options turned on was chosen as the foundation for the history matching trials of all five wells. It can also be concluded that during the first 30 days production, capillary end effect has the biggest impact on gas rates.
Figure 4.12: Simulation results of gas production for Well D using all the damage combinations and plots of the field data.

4.4 Sensitivity to Reservoir and Fracture Variables

To conduct history matching in a more efficient and effective way, analyzing cleanup process’ sensitivity to some single variables was carried out first and the results are presented in this section. For the purpose of being concise, only one well’s results (Well D) will be shown with its sensitivity to six representative input variables.

4.4.1 Reservoir Matrix Permeability

One of the underlying assumptions for this simulator is that the reservoir matrix is homogeneous and isotropic porous media, thus the model requires one input value for the matrix
permeability. The permeability tests on vacuum dried samples at 212°F from the Cana Field (Frank, 2013b) have a maximum value of 0.000664 md, a minimum of 0.000041 md, and a mean of 0.000238 md. Therefore, a set of simulation studies was conducted for Well D (Table 4.4).

Table 4.4 Sensitivity Analysis of Reservoir Matrix Permeability for Well D

<table>
<thead>
<tr>
<th>Run #</th>
<th>Reservoir Matrix Permeability (md)</th>
</tr>
</thead>
<tbody>
<tr>
<td>1</td>
<td>0.00010</td>
</tr>
<tr>
<td>2</td>
<td>0.00020</td>
</tr>
<tr>
<td>3</td>
<td>0.00050</td>
</tr>
<tr>
<td>4</td>
<td>0.00055</td>
</tr>
</tbody>
</table>

The simulation results of gas and water rates during the cleanup stage for Well D are shown in Figures 4.14 and 4.15, respectively.
As seen from Figure 4.14, a permeability of 0.0005 md for the reservoir matrix yielded the best match for historical gas producing rates. As permeability input increases in the model, the system produces more gas. The higher permeability values make the initial gas climbing profile steeper while after the peak rates all the cases have the same decline trend. In the meanwhile, the 0.0005 md permeability input brought out the lowest water producing peak rate (Figure 4.15).

4.4.2 Fracture Permeability at Closure

Another important variable which has a direct impact on the well flowback profile is the hydraulic fracture permeability. The simulator requires the user to input a value of fracture permeability at closure for setting up the model. During simulation, after the fracture reaches its minimum width (i.e. after the value of fracture permeability at closure is reached), the fracture will continue to compact as fracture pressure decreases, the result of which is that the fracture porosity
and permeability also decreases continuously. The default input for the closure permeability in the simulator was obtained from FracproPT 2007 and equals 311,000 md (Charoenwongsa, 2011).

Figure 4.15: Simulation results of water rates for different matrix permeability values during the cleanup stage for Well D.

A summary of the simulation runs in this section is listed in Table 4.5.

Table 4.5: Sensitivity Analysis of Fracture Closure Permeability for Well D

<table>
<thead>
<tr>
<th>Run #</th>
<th>Fracture Closure Permeability (md)</th>
</tr>
</thead>
<tbody>
<tr>
<td>1</td>
<td>200,000</td>
</tr>
<tr>
<td>2</td>
<td>250,000</td>
</tr>
<tr>
<td>3</td>
<td>300,000</td>
</tr>
</tbody>
</table>

The simulation results of gas and water rates during the cleanup stage for Well D are shown in Figures 4.16 and 4.17, respectively.

As indicated by Figures 4.16 and 4.17, once the matrix permeability is fixed at a low value (0.0005 md in this case), fracture closure permeability does not have much impact on the gas
flowing rates for the value range of 200,000 md to 300,000 md. A higher value helps gas production increase to its peak more quickly (2~3 days faster for 200,000 md than for 300,000 md), whereas until after the peak rates are reached the producing profiles are the same regardless of the different fracture permeability inputs. However, the larger the fracture closure permeability, the higher the water flowback peak rates.

4.4.3 Net Pressure

The third parameter to look at is the net pressure, which is defined as the injection pressure minus the minimum horizontal stress in this research. The input information is listed in Table 4.6, with the plots of the simulation results presented in Figures 4.18 and 4.19.

It can be concluded that a net pressure of either 190 psi or 250 psi gives a very good match for gas rates, whereas as net pressure increases in the model, the water production will have a much
larger peak rate.

Figure 4.17: Simulation results of water rates for different fracture closure permeabilities during the cleanup stage for Well D.

<table>
<thead>
<tr>
<th>Run #</th>
<th>Net Pressure (psi)</th>
</tr>
</thead>
<tbody>
<tr>
<td>1</td>
<td>150</td>
</tr>
<tr>
<td>2</td>
<td>190</td>
</tr>
<tr>
<td>3</td>
<td>250</td>
</tr>
</tbody>
</table>

Table 4.6: Sensitivity Analysis of Net Pressure for Well D

Based on the PKN fracture model adopted by this simulator (Charoenwongsa, 2011), the maximum width of the vertical fracture is directly proportional to the net pressure \((P_f - \sigma_{h,\text{min}})\), as shown in Equation 4.1. Thus, the fracture created in the model tends to be narrower for lower net pressure formations, which means the fracture will be longer and yields more reservoir contact for the flow simulations, and makes the sensitivity analysis results for gas production justifiable.

\[
w_{f,max} = \frac{2(1-v^2)(P_f-\sigma_{h,\text{min}})k_f}{E} \tag{4.1}
\]

where,
\( w_{f,\text{max}} \) = maximum fracture width

\( P_f \) = fracture pressure, whose initial value equals to the injection pressure in the simulations

\( \sigma_{h,\text{min}} \) = minimum horizontal stress

\( L_f \) = fracture half length

\( E \) = Young’s modulus

\( v \) = Poissson’s ratio

---

**Figure 4.18**: Simulation results of gas rates for different net pressures during the cleanup stage for Well D.

4.4.4 Young’s Modulus

Next, well cleanup performance’s sensitivity to Young’s modulus is studied. Young’s modulus is one of the many parameters which can be used to describe the brittleness of a rock type and therefore plays an important role in fracturing design. The input information is listed in Table 4.7, with the simulation results plotted in Figures 4.20 and 4.21.
As seen from Figure 4.20, the higher the Young’s modulus, the larger the gas producing rates from the 10th day toward the end of the first month, however, water flowback peak rates tend to be lower for higher Young’s modulus formations.

Based on the PKN fracture model adopted by this simulator, the maximum width of the vertical fracture is inversely proportional to Young’s modulus as shown by Equation 4.1. Thus, the fracture created in the model tends to be narrower for higher Young’s modulus formations, which means the fracture will be longer and yield more reservoir contact and make the simulation results more justifiable. From the field practice standpoint, formations with higher Young’s modulus values are easier to break. This is also consistent with the numerical analysis.
Figure 4.20: Sensitivity analysis of Young’s modulus for gas rates during the cleanup stage for Well D.

Figure 4.21: Sensitivity analysis of Young’s modulus for water rates during the cleanup stage for Well D.
4.4.5 Reservoir Matrix Porosity

Another parameter to check in the sensitivity analysis is the reservoir matrix porosity. The major input for Well D’s production simulation is listed in Table 4.8, with the simulation results shown in Figures 4.22 and 4.23.

Table 4.8: Input Information for Sensitivity Analysis of Reservoir Matrix Porosity for Well D

<table>
<thead>
<tr>
<th>Run #</th>
<th>Reservoir Matrix Porosity (-)</th>
</tr>
</thead>
<tbody>
<tr>
<td>1</td>
<td>0.065</td>
</tr>
<tr>
<td>2</td>
<td>0.070</td>
</tr>
<tr>
<td>3</td>
<td>0.080</td>
</tr>
</tbody>
</table>

Figure 4.22: Sensitivity analysis of reservoir matrix porosity for gas rates during the cleanup stage for Well D.

As seen from both figures above, for the lower reservoir matrix permeability case (0.0005 md in this case), porosity values between 0.065 and 0.080 make little difference in terms of the first 30 days’ gas or water production.

4.4.6 Formation Pressure Gradient

The sixth variable shown for sensitivity analysis is the formation pressure gradient. The input
As seen from Figure 4.24, the higher the geo-pressure gradient, the larger the amount of gas produced from the system. In addition, the gas producing profile or “curve shape” is controlled by the formation pressure gradient. A larger gradient (e.g. the 0.550 psi/ft case) gives rise to a larger slope for gas rate until it reaches the peak value, and a steady decline is observed thereafter. However, for a lower gradient scenario, it takes a longer time to reach the peak and the gas rate climbs more gently. The decline part also gently dips. Especially in the 0.400 psi/ft case, gas

Table 4.9: Input Information for Sensitivity Analysis of Formation Pressure Gradient for Well D

<table>
<thead>
<tr>
<th>Run #</th>
<th>Formation Pressure Gradient (psi/ft)</th>
</tr>
</thead>
<tbody>
<tr>
<td>1</td>
<td>0.400</td>
</tr>
<tr>
<td>2</td>
<td>0.433</td>
</tr>
<tr>
<td>3</td>
<td>0.500</td>
</tr>
<tr>
<td>4</td>
<td>0.550</td>
</tr>
</tbody>
</table>
production finally just flattened out. Also, indicated by the curves, this reservoir is “overpressured”, with a higher formation pressure gradient compared to fresh water’s 0.433 psi/ft. Water flowback peak rates are larger for the higher formation pressure cases (Figure 4.25).

4.4.7 Summary and Discussions

All of the above demonstrated variables except the reservoir matrix porosity have an impact on gas or water producing rates in the first 30 days timeframe. For the gas, the formation pressure gradient determines the shape (both in the climbing and declining part) of the curve. Reservoir matrix permeability, net pressure, and Young’s modulus tend to shift the curves up and down as their values are changed. More specifically the matrix permeability indicates the formation’s ability to transmit the gas phase, while net pressure and Young’s modulus affect the final fracture
dimensions and thus have an impact on the deliverability of a well.

Figure 4.25: Sensitivity analysis of formation pressure gradient for water rates during the cleanup stage for Well D.

These are six example variables among many others that were examined in sensitivity analysis before history matching, and the conclusions give direction in the matching process as presented in Section 4.5.

4.5 History Matching the Five Cana Wells

Based on the insights gained from the work shown in previous sections, the history matching results along with the key input information for each of the five wells are presented in the following. As discussed in Section 3.2, some reservoir and fracture related inputs are adjustable and used to achieve good matches. For the operational variables, input values are fixed and exactly the same as the field situation.
4.5.1 Well A

Detailed input information is listed in Table 4.10, and the history matching results for Well A’s gas and water flow rates for the first 30 days are plotted in Figures 4.26 and 4.27, respectively.

Table 4.10: Input Information for Matching Well A

<table>
<thead>
<tr>
<th>Operational Variables</th>
<th></th>
</tr>
</thead>
<tbody>
<tr>
<td>Injection rate (bpm)</td>
<td>92.8</td>
</tr>
<tr>
<td>Injection rate (bpd)</td>
<td>133668</td>
</tr>
<tr>
<td>Injection volume per perf cluster (gal)</td>
<td>202832</td>
</tr>
<tr>
<td>Injection volume per 2 perf clusters (bbl)</td>
<td>9658.7</td>
</tr>
<tr>
<td>Shut-in time (days)</td>
<td>1.0</td>
</tr>
<tr>
<td>Control BHP decline rate (-)</td>
<td>-0.10</td>
</tr>
<tr>
<td>Minimum BHP (psi)</td>
<td>3500</td>
</tr>
</tbody>
</table>

<table>
<thead>
<tr>
<th>Reservoir Data</th>
<th></th>
</tr>
</thead>
<tbody>
<tr>
<td>Formation pressure gradient (psi/ft)</td>
<td>0.54</td>
</tr>
<tr>
<td>Reservoir depth (ft)</td>
<td>12894</td>
</tr>
<tr>
<td>Reservoir porosity (-)</td>
<td>0.095</td>
</tr>
<tr>
<td>Reservoir permeability (md)</td>
<td>0.00065</td>
</tr>
<tr>
<td>Young's modulus (psi)</td>
<td>8.00E+06</td>
</tr>
<tr>
<td>Reservoir pay thickness (ft)</td>
<td>150</td>
</tr>
</tbody>
</table>

<table>
<thead>
<tr>
<th>Fracture Data</th>
<th></th>
</tr>
</thead>
<tbody>
<tr>
<td>Fracture permeability at closure (md)</td>
<td>311000</td>
</tr>
<tr>
<td>Fracture porosity at closure (-)</td>
<td>0.3</td>
</tr>
<tr>
<td>Net pressure (psi)</td>
<td>160</td>
</tr>
</tbody>
</table>

As seen in Figure 4.26, field gas production experienced a sudden drop around 16~17 days after the well was opened to the flowback tank, which makes the simulation results deviate from the real data. Field records reveal that the total dissolved solids (TDS) indicator increased significantly around that time. Since freshwater was pumped while treating the well, an abrupt increase of TDS would indicate a portion of formation water was flowing out then, and maybe lowering the gas rate.
Figure 4.26: History matching result of gas rates for Well A.

Figure 4.27: History matching result of water rates for Well A.
4.5.2 Well B

Detailed input information is listed in Table 4.11, and the history matching results for Well B’s gas and water flow rates for the first 30 days are plotted in Figures 4.28 and 4.29, respectively.

Table 4.11: Input Information for Matching Well B

<table>
<thead>
<tr>
<th>Operational Variables</th>
<th></th>
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<tbody>
<tr>
<td>Injection rate (bpm)</td>
<td>90.3</td>
</tr>
<tr>
<td>Injection rate (bpd)</td>
<td>130000</td>
</tr>
<tr>
<td>Injection volume per perf cluster (gal)</td>
<td>188030</td>
</tr>
<tr>
<td>Injection volume per 2 perf clusters (bbl)</td>
<td>8953.8</td>
</tr>
<tr>
<td>Shut-in time (days)</td>
<td>1</td>
</tr>
<tr>
<td>Control BHP decline rate (-)</td>
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</tr>
<tr>
<td>Minimum BHP (psi)</td>
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<table>
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</thead>
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<tr>
<td>Formation pressure gradient (psi/ft)</td>
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</tr>
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<td>Reservoir depth (ft)</td>
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</tr>
<tr>
<td>Reservoir porosity (-)</td>
<td>0.050</td>
</tr>
<tr>
<td>Reservoir permeability (md)</td>
<td>0.0001</td>
</tr>
<tr>
<td>Young's modulus (psi)</td>
<td>8.00E+06</td>
</tr>
<tr>
<td>Reservoir pay thickness (ft)</td>
<td>150</td>
</tr>
</tbody>
</table>

<table>
<thead>
<tr>
<th>Fracture Data</th>
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</tr>
</thead>
<tbody>
<tr>
<td>Fracture permeability at closure (md)</td>
<td>300000</td>
</tr>
<tr>
<td>Fracture porosity at closure (-)</td>
<td>0.3</td>
</tr>
<tr>
<td>Net pressure (psi)</td>
<td>185</td>
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</tbody>
</table>

As can be observed from Figure 4.28, after the gas peak rate is reached, the simulation results using a porosity input value of 0.050 overestimate the real data a little. For some other porosity values lower than 0.050, the simulation results yield more instability issues and uncertainties (Figure 4.30). The water history matching result will be discussed in Section 4.5.6.

4.5.3 Well C

Detailed input information is listed in Table 4.12, and the history matching results for Well C’s gas and water flow rates for the first 30 days are plotted in Figures 4.31 and 4.32, respectively.
Figure 4.28: History matching result of Well B’s gas rates.

Figure 4.29: History matching result of Well B’s water rates.
Figure 4.30: Simulation results of gas production for Well B using porosity values other than 0.050.

As seen from Figure 4.31, the early time gas increase is not perfect in that the field data represents a more aggressive gas rates climbing. This will be discussed in Section 4.5.6.

4.5.4 Well D

Detailed input information is listed in Table 4.13, and the history matching results for Well D’s gas and water flow rates for the first 30 days are plotted in Figures 4.33 and 4.34, respectively. As can be observed from Figure 4.33, very good matches were achieved for field gas rates.

4.5.5 Well E

Detailed input information is listed in Table 4.14, and the history matching results for Well E’s gas and water flow rates for the first 30 days are plotted in Figures 4.35 and 4.36, respectively.
Table 4.12: Input Information for Matching Well C

<table>
<thead>
<tr>
<th>Operational Variables</th>
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<tbody>
<tr>
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</tr>
<tr>
<td>Injection rate (bpd)</td>
<td>138256</td>
</tr>
<tr>
<td>Injection volume per perf cluster (gal)</td>
<td>197784</td>
</tr>
<tr>
<td>Injection volume per 2 perf clusters (bbl)</td>
<td>9418.3</td>
</tr>
<tr>
<td>Shut-in time (days)</td>
<td>4.2</td>
</tr>
<tr>
<td>Control BHP decline rate (-)</td>
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</tr>
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<td>Minimum BHP (psi)</td>
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<td>Formation pressure gradient (psi/ft)</td>
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</tr>
<tr>
<td>Reservoir depth (ft)</td>
<td>12926</td>
</tr>
<tr>
<td>Reservoir porosity (-)</td>
<td>0.06</td>
</tr>
<tr>
<td>Reservoir permeability (md)</td>
<td>0.0002</td>
</tr>
<tr>
<td>Young's modulus (psi)</td>
<td>1.00E+07</td>
</tr>
<tr>
<td>Reservoir pay thickness (ft)</td>
<td>160</td>
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</tbody>
</table>

<table>
<thead>
<tr>
<th>Fracture Data</th>
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</tr>
</thead>
<tbody>
<tr>
<td>Fracture permeability at closure (md)</td>
<td>311000</td>
</tr>
<tr>
<td>Fracture porosity at closure (-)</td>
<td>0.1</td>
</tr>
<tr>
<td>Net pressure (psi)</td>
<td>150</td>
</tr>
</tbody>
</table>

During the first 30 days’ production of this well, the field crew changed the choke size very frequently and shut the well for a while on the 6th day, both of which can be seen in the “jumping around” of the field data on Figure 4.35. However, the current simulator does not capture the surface operations (for example, changing choke size) during well flowback, and in simulation the BHP is following a simple exponential declining profile.
Figure 4.31: History matching result of Well C’s gas rates.

Figure 4.32: History matching result of Well C’s water rates.
Table 4.13: Input Information for Matching Well D

<table>
<thead>
<tr>
<th>Operational Variables</th>
<th></th>
</tr>
</thead>
<tbody>
<tr>
<td>Injection rate (bpm)</td>
<td>94.0</td>
</tr>
<tr>
<td>Injection rate (bpd)</td>
<td>135360</td>
</tr>
<tr>
<td>Injection volume per perf cluster (gal)</td>
<td>191519</td>
</tr>
<tr>
<td>Injection volume per 2 perf clusters (bbl)</td>
<td>9119.9</td>
</tr>
<tr>
<td>Shut-in time (days)</td>
<td>2.8</td>
</tr>
<tr>
<td>Control BHP decline rate (-)</td>
<td>-0.17</td>
</tr>
<tr>
<td>Minimum BHP (psi)</td>
<td>4000</td>
</tr>
<tr>
<td>Salinity of injected water (ppm)</td>
<td>10,000</td>
</tr>
</tbody>
</table>

<table>
<thead>
<tr>
<th>Reservoir Data</th>
<th></th>
</tr>
</thead>
<tbody>
<tr>
<td>Formation pressure gradient (psi/ft)</td>
<td>0.5</td>
</tr>
<tr>
<td>Reservoir depth (ft)</td>
<td>12572</td>
</tr>
<tr>
<td>Reservoir porosity (-)</td>
<td>0.07</td>
</tr>
<tr>
<td>Reservoir permeability (md)</td>
<td>0.0005</td>
</tr>
<tr>
<td>Young's modulus (psi)</td>
<td>6.00E+06</td>
</tr>
<tr>
<td>Reservoir pay thickness (ft)</td>
<td>140</td>
</tr>
</tbody>
</table>

<table>
<thead>
<tr>
<th>Fracture Data</th>
<th></th>
</tr>
</thead>
<tbody>
<tr>
<td>Fracture permeability at closure (md)</td>
<td>250000</td>
</tr>
<tr>
<td>Fracture porosity at closure (-)</td>
<td>0.3</td>
</tr>
<tr>
<td>Net pressure (psi)</td>
<td>190</td>
</tr>
</tbody>
</table>

Figure 4.33: History matching result of Well D’s gas rates.
Figure 4.34: History matching result of Well D’s water rates.

Figure 4.35: History matching result of Well E’s gas rates.
Table 4.14: Input Information for Matching Well E

<table>
<thead>
<tr>
<th>Operational Variables</th>
<th></th>
</tr>
</thead>
<tbody>
<tr>
<td>Injection rate (bpm)</td>
<td>95.9</td>
</tr>
<tr>
<td>Injection rate (bpd)</td>
<td>138144</td>
</tr>
<tr>
<td>Injection volume per perf cluster (gal)</td>
<td>195215</td>
</tr>
<tr>
<td>Injection volume per 2 perf clusters (bbl)</td>
<td>9295.9</td>
</tr>
<tr>
<td>Shut-in time (days)</td>
<td>3.5</td>
</tr>
<tr>
<td>Control BHP decline rate (-)</td>
<td>-0.3</td>
</tr>
<tr>
<td>Minimum BHP (psi)</td>
<td>3300</td>
</tr>
<tr>
<td>Salinity of injected water (ppm)</td>
<td>0</td>
</tr>
</tbody>
</table>

<table>
<thead>
<tr>
<th>Reservoir Data</th>
<th></th>
</tr>
</thead>
<tbody>
<tr>
<td>Formation pressure gradient (psi/ft)</td>
<td>0.5</td>
</tr>
<tr>
<td>Reservoir depth (ft)</td>
<td>12823</td>
</tr>
<tr>
<td>Reservoir porosity (-)</td>
<td>0.07</td>
</tr>
<tr>
<td>Reservoir permeability (md)</td>
<td>0.0005</td>
</tr>
<tr>
<td>Young's modulus (psi)</td>
<td>1.00E+07</td>
</tr>
<tr>
<td>Reservoir pay thickness (ft)</td>
<td>150</td>
</tr>
</tbody>
</table>

<table>
<thead>
<tr>
<th>Fracture Data</th>
<th></th>
</tr>
</thead>
<tbody>
<tr>
<td>Fracture permeability at closure (md)</td>
<td>311000</td>
</tr>
<tr>
<td>Fracture porosity at closure (-)</td>
<td>0.3</td>
</tr>
<tr>
<td>Net pressure (psi)</td>
<td>185</td>
</tr>
</tbody>
</table>

Figure 4.36: History matching result of Well E’s water rates.
4.5.6 Summary and Discussions

It can be seen from the previous sections that some moderately good matches for gas producing rates have been achieved for all five of the Cana wells. The early time gas delay (compared to water flowback) has been reproduced in most cases. Water rates’ matching results were not as satisfactory as the gas matches, however, the characteristic of reaching the peak water rate on the second or third day after the wells are put on production has been realized and demonstrated in the simulation outputs.

The discrepancies between the simulated and real water flowback profiles are typically the result of the model’s overestimation of the peak rate and exaggeration of the later decline profile, which shows a more aggressive one compared to the real case which has a shallower decline in daily rates. One reason that may account for the unsatisfactory matching is due to the relative permeability setting used. In this research all the models used an initial water saturation, $S_{wi}$, of 0.45 (Table 4.1), which equals the input value for the irreducible water saturation of the reservoir matrix (Figure 4.1). This, however, might not be realistic for some shale gas reservoirs, where the initial water saturation is lower than the irreducible value (i.e. sub-irreducible). This would cause a large amount of injected water to be trapped in the reservoir, and only the portion above the irreducible threshold would be able to flow back. As presented in Section 2.5.2, initial water saturation for the Cana Woodford Shale is reported to be around 25% (Grieser and Talley, 2012). Therefore, the shale reservoir in the Cana Field may have sub-irreducible initial water saturation.

Some past research concludes that “this (a correct set of relative permeability curves) may be of particular importance to correctly simulate the clean-up phase, and account for potentially large volumes of pumped water trapped in the fracture network” (KAPPA, 2011). However, the sub-irreducible initial water saturation option was not included in the current simulator.

It is also believed that the water flowback profile has a lot to do with the complex fractures system, which was not included in the consideration of the current simulator. The fact that some natural fractures might exist and hold a certain amount of water would make water flow back in a
more gentle way which is consistent with the Cana Field observation. For a non-water-wetting situation, there is also a possibility that some water is trapped in the secondary fractures during initial production, as discussed in Chapter 2 (Figure 2.3). The water saturation distributions for an example well (Well A) right before production is initiated, after 7.7 days of production, and after 30 days of production are plotted in Figures 4.37, 4.38, and 4.39 respectively. It can be concluded that during early production, fracturing fluid continues to leakoff into the near fracture tip region. Some water might still be trapped in that region after 30 days of production, which is not captured well by the simulator.

Figure 4.37: Matrix water saturation distribution immediately before production for Well A. Note that one quarter of the reservoir is plotted and the wellbore is located at the origin.
Figure 4.38: Matrix water saturation distribution after 7.7 days of production for Well A.
Figure 4.39: Matrix water saturation distribution after 30 days of production for Well A.

The operational, reservoir, and fracture input used for matching all five wells are summarized in Table 4.15. The shaded area indicates the non-fixed variables and the associated values for matching each well.
Table 4.15: Summary of Reservoir and Fracture Input for Matching the Five Cana Wells

<table>
<thead>
<tr>
<th>Operational Variables</th>
<th>A</th>
<th>B</th>
<th>C</th>
<th>D</th>
<th>E</th>
<th>Average</th>
</tr>
</thead>
<tbody>
<tr>
<td>Injection rate (bpm)</td>
<td>92.8</td>
<td>90.3</td>
<td>96.0</td>
<td>94.0</td>
<td>95.9</td>
<td>93.8</td>
</tr>
<tr>
<td>Injection rate (bpd)</td>
<td>133668</td>
<td>130000</td>
<td>138256</td>
<td>135360</td>
<td>138144</td>
<td>135086</td>
</tr>
<tr>
<td>Injection volume per perf cluster (gal)</td>
<td>202832</td>
<td>188030</td>
<td>197784</td>
<td>191519</td>
<td>195215</td>
<td>195076</td>
</tr>
<tr>
<td>Injection volume per 2 perf clusters (bbl)</td>
<td>9658.7</td>
<td>8953.8</td>
<td>9418.3</td>
<td>9119.9</td>
<td>9295.9</td>
<td>9289.3</td>
</tr>
<tr>
<td>Shut-in time (days)</td>
<td>1.0</td>
<td>1.0</td>
<td>4.2</td>
<td>2.8</td>
<td>3.5</td>
<td>2.5</td>
</tr>
<tr>
<td>Control BHP decline rate (-)</td>
<td>-0.10</td>
<td>-0.12</td>
<td>-0.49</td>
<td>-0.17</td>
<td>-0.30</td>
<td>-0.24</td>
</tr>
<tr>
<td>Minimum BHP (psi)</td>
<td>3500</td>
<td>2650</td>
<td>3100</td>
<td>4000</td>
<td>3300</td>
<td>3310</td>
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<tr>
<td>Reservoir Data</td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Formation pressure gradient (psi/ft)</td>
<td>0.54</td>
<td>0.50</td>
<td>0.45</td>
<td>0.50</td>
<td>0.50</td>
<td>0.50</td>
</tr>
<tr>
<td>Reservoir depth (ft)</td>
<td>12894</td>
<td>12487</td>
<td>12926</td>
<td>12572</td>
<td>12823</td>
<td>12740</td>
</tr>
<tr>
<td>Reservoir porosity (-)</td>
<td>0.095</td>
<td>0.050</td>
<td>0.060</td>
<td>0.070</td>
<td>0.070</td>
<td>0.069</td>
</tr>
<tr>
<td>Reservoir permeability (md)</td>
<td>0.00065</td>
<td>0.00010</td>
<td>0.00020</td>
<td>0.00050</td>
<td>0.00050</td>
<td>0.00039</td>
</tr>
<tr>
<td>Young's modulus (psi)</td>
<td>8.00E+06</td>
<td>8.00E+06</td>
<td>1.00E+07</td>
<td>6.00E+06</td>
<td>1.00E+07</td>
<td>8.40E+06</td>
</tr>
<tr>
<td>Reservoir pay thickness (ft)</td>
<td>150</td>
<td>150</td>
<td>160</td>
<td>140</td>
<td>150</td>
<td>150</td>
</tr>
<tr>
<td>Fracture Data</td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Fracture permeability at closure (md)</td>
<td>311000</td>
<td>300000</td>
<td>311000</td>
<td>250000</td>
<td>311000</td>
<td>296600</td>
</tr>
<tr>
<td>Fracture porosity at closure (-)</td>
<td>0.30</td>
<td>0.30</td>
<td>0.10</td>
<td>0.30</td>
<td>0.30</td>
<td>0.26</td>
</tr>
<tr>
<td>Net pressure (psi)</td>
<td>160</td>
<td>185</td>
<td>150</td>
<td>190</td>
<td>185</td>
<td>174</td>
</tr>
</tbody>
</table>
As presented in Table 4.15, the wells with longer shut-in periods after the fracturing treatment (especially Wells C and E which have shut-in durations of more than 3 days), have larger BHP decline rate coefficients in absolute values. This means the BHP (i.e. equal to pressure inside the fracture for this simulator) declines faster and fracture closure happens sooner, thus gas will flow out of the reservoir more quickly. This is consistent with the field observations that Wells C and E have a gas breakthrough time of less than 5 days compared to other wells, which see gas in 7 to 8 days. Physically this phenomenon is also explainable. Although the well is shut in at the surface, the gas tends to flow into and be accumulated in the near-wellbore region. Once the well is opened, that gas in the near well region could be accelerated to an instantaneous high producing rate (Whitson et al., 2012). The five wells’ shut-in durations, time to initial gas production after opening the well, and the sum of the former two which represents a “total waiting time” for gas are listed in Table 4.16. In this research, the time zero in well shut-in is equal to the time point after all the stages have been fractured. However, as the five wells were completed using the plug-and-perf method and it could take several days to finish fracturing all the stages, the actual shut-in time will be different for each stage. For example, the stage at the toe experiences a longer shut-in duration than the stage at the heel. But this effect is not considered in this research.

Table 4.16: Shut-in Duration, Time to Initial Gas Production after Opening the Well, and Total Gas Waiting Time for the Five Cana Wells

<table>
<thead>
<tr>
<th>Well #</th>
<th>Shut-in Duration (day)</th>
<th>Time to Initial Gas Production after Opening the Well (day)</th>
<th>Total Gas Waiting Time (day)</th>
</tr>
</thead>
<tbody>
<tr>
<td>A</td>
<td>1.0</td>
<td>7.9</td>
<td>8.9</td>
</tr>
<tr>
<td>B</td>
<td>1.0</td>
<td>7.2</td>
<td>8.2</td>
</tr>
<tr>
<td>C</td>
<td>4.2</td>
<td>4.3</td>
<td>8.5</td>
</tr>
<tr>
<td>D</td>
<td>2.8</td>
<td>8.0</td>
<td>10.8</td>
</tr>
<tr>
<td>E</td>
<td>3.5</td>
<td>4.0</td>
<td>7.5</td>
</tr>
</tbody>
</table>

As shown by the data in the above table, Wells C and E enjoyed a quicker gas production, however this advantage does not outweigh the time loss during those wells’ shut-in, as the total gas waiting time does not differ much from each other across the five wells. Based on the observation of these five wells, one of the pieces of information that might be useful for the field crew, is that extended shut-in durations do not hurt in terms of delaying the gas production in the overall situation. This is also consistent with some past research which concluded that for a low-permeability stimulated well, shut-in operation could have no downsides in terms of losing.
recovery (Whitson et al., 2012).

The minimum BHP is also a variable that needs to be changed for matching the production data. As discussed in Section 3.2, the BHP decline profile is modeled through exponentially interpolating between the initial reservoir pressure and the final minimum BHP. At the start of the flow back, the BHP is equal to the initial reservoir pressure. As production advances, it will finally drop to the minimum value and stay constant. Since only the surface pressure within the first 30 days of production is available, the minimum BHP is also an unknown and non-fixed variable.

The average hydrostatic gradient for reservoir pressure is 0.50 psi/ft, which is lower than an assumed value of 0.68 psi/ft in the literature (Grieser and Talley, 2012). As discussed in Section 4.4.6, increasing the hydrostatic pressure gradient will help initial gas production increase in a more aggressive way, i.e. the gas rate curves might have a steeper increase. That might lead to better history matching results for early time gas rates climbing, especially for the case of Well C (Figure 4.31), which also indicates that the real formation pressure gradient could be higher than the input values used. The simulator was not robust, however, after the pressure gradient was increased even a little for the wells in this research (originally the simulator was designed for a reservoir of 8000 ft deep with a 0.45 psi/ft gradient, but the five wells in this thesis are all deeper than 12000 ft). This knowledge is integrated into the recommendations for improving this tool, which is discussed in Chapter 5.

Both the choke setting during flowback and how fast the fracturing operation can be finished for all stages are believed to have an impact on the gas rates for the first 30 days of production. The gas producing profiles for the five wells are plotted in Figure 4.40. The average choke sizes during the first 30 days and the average time spent for fracturing each stage are summarized in Table 4.17. Please note that these five wells differs a little regarding the frac job size and they are believed to be comparable in terms of production performance.

As can be observed from Figure 4.40, Wells C and E have almost the same gas increasing profile, which means the formation pressure gradients should be quite similar. The reason that Well E had a smaller average choke size is because it was changed to a relatively larger choke (19/64 inch) soon after first gas, then the choke size was gradually reduced to the range of 13/64 to 15/64 inch. However, Well C was opened on 16/64 inch, and within six days the choke size was increased to 18/64 inch and stayed constant. The percentage of the fracturing fluid recovered and the cumulative gas production for the first 30 days of production for the five wells are listed in Table
Figure 4.40: Gas producing profiles for the five Cana wells.

Table 4.17: The Average Choke Sizes during the First 30 Days Flowback and the Average Time Spent For Fracturing Each Stage for the Five Cana Wells

<table>
<thead>
<tr>
<th>Well #</th>
<th>Choke Size Average for the First 30 days (x/64 inch)</th>
<th>(Last - First Frac Date)/# of Stages (day)</th>
</tr>
</thead>
<tbody>
<tr>
<td>A</td>
<td>18</td>
<td>0.38</td>
</tr>
<tr>
<td>B</td>
<td>18</td>
<td>0.78</td>
</tr>
<tr>
<td>C</td>
<td>18</td>
<td>0.33</td>
</tr>
<tr>
<td>D</td>
<td>17</td>
<td>0.44</td>
</tr>
<tr>
<td>E</td>
<td>15</td>
<td>0.33</td>
</tr>
</tbody>
</table>

For Wells A, B, and D, they were drilled into the similar pressure gradient zones. From Tables 4.17 and 4.18, it can be concluded that the more quickly the fracturing operation is done for each stage, the larger amount of gas can be produced during the first 30 days flowback. Therefore, saving time during multi-stage fracturing is recommended for field operations in the Cana Field, for the purpose of having better gas producing performances during the first 30 days timeframe.
Also among the five wells, there does not exist any obvious correlations between the percentage of fluid flowback and the gas production. The leakoff volumes from simulation outputs and the calculated fracture efficiencies are listed in Table 4.19.

Table 4.18: Percentage of the Fracturing Fluid Recovered and Cumulative Gas Production for the First 30 Days of Production for the Five Cana Wells

<table>
<thead>
<tr>
<th>Well #</th>
<th>% of Fluid Recovered (-)</th>
<th>First 30 days Cum Gas after Opening the Well (MMCF)</th>
<th>First 30 days Cum Gas after Fracturing (MMCF)</th>
</tr>
</thead>
<tbody>
<tr>
<td>A</td>
<td>36.03%</td>
<td>122.485</td>
<td>117.514</td>
</tr>
<tr>
<td>B</td>
<td>29.15%</td>
<td>61.414</td>
<td>59.071</td>
</tr>
<tr>
<td>C</td>
<td>17.82%</td>
<td>100.393</td>
<td>86.803</td>
</tr>
<tr>
<td>D</td>
<td>18.35%</td>
<td>106.195</td>
<td>95.979</td>
</tr>
<tr>
<td>E</td>
<td>19.51%</td>
<td>175.016</td>
<td>154.620</td>
</tr>
</tbody>
</table>

Table 4.19: Fracture Efficiency and Leakoff Volume for the Five Cana Wells

<table>
<thead>
<tr>
<th>Well #</th>
<th>Total Fluid Pumped per Fracture (bbl)</th>
<th>Maximum Leakoff Volume per Fracture (bbl)</th>
<th>Fracture Efficiency (-)</th>
</tr>
</thead>
<tbody>
<tr>
<td>A</td>
<td>9658.7</td>
<td>1692.8</td>
<td>82.5%</td>
</tr>
<tr>
<td>B</td>
<td>8953.8</td>
<td>585.5</td>
<td>93.5%</td>
</tr>
<tr>
<td>C</td>
<td>9418.3</td>
<td>779.5</td>
<td>91.7%</td>
</tr>
<tr>
<td>D</td>
<td>9119.9</td>
<td>1021.6</td>
<td>88.8%</td>
</tr>
<tr>
<td>E</td>
<td>9295.9</td>
<td>1050.4</td>
<td>88.7%</td>
</tr>
</tbody>
</table>

As seen from Table 4.15, there exists very good consistencies for the reservoir related inputs across the five wells. In addition, the averaged values are reasonable. The average inputs for matrix porosity and permeability fall into the experimental data range of the Cana core analysis (Frank, 2013b), and the average reservoir pay thickness is consistent with those numbers reported from the field’s stimulation database (Frank, 2013a) and the literature (Grieser and Talley, 2012). The Young’s modulus values do not deviate from the literature (Kumar et al., 2012). Therefore, the set of averaged values are believed to reflect the reservoir conditions in the Cana Field, as listed in Table 4.20.

Please note that a homogeneous and isotropic reservoir matrix is the underlying assumption for this research, so the above proposed permeability and porosity values describe the whole flow system in an “equivalent” manner. For example, natural fractures might exist and enhance fluid flow, then their role and effect are included in those equivalent values for reservoir permeability.
and porosity.

<table>
<thead>
<tr>
<th>Reservoir Parameters</th>
<th>Minimum</th>
<th>Maximum</th>
<th>Average</th>
</tr>
</thead>
<tbody>
<tr>
<td>Reservoir porosity (–)</td>
<td>0.050</td>
<td>0.095</td>
<td>0.069</td>
</tr>
<tr>
<td>Reservoir permeability (md)</td>
<td>0.00010</td>
<td>0.00065</td>
<td>0.00039</td>
</tr>
<tr>
<td>Young's modulus (psi)</td>
<td>6.0E+06</td>
<td>1.0E+07</td>
<td>8.4E+06</td>
</tr>
<tr>
<td>Reservoir pay thickness (ft)</td>
<td>140</td>
<td>160</td>
<td>150</td>
</tr>
<tr>
<td>Formation pressure gradient (psi/ft)</td>
<td>&gt; 0.45</td>
<td>0.54</td>
<td>&gt; 0.50</td>
</tr>
</tbody>
</table>
CHAPTER 5

CONCLUSIONS AND RECOMMENDATIONS

The following presents the major conclusions and the future work recommended from the studies in this research.

5.1 Conclusions

For the purposes of this thesis, numerical modeling of well cleanup behavior, including studying initial production parameters as well as history matching well cleanup data for the Cana Field in Oklahoma has been conducted. The following conclusions were drawn from the sensitivity analysis and history matching:

1. Using the simulation outputs, moderately good matches with field historical data were achieved. Based on the discussions in Section 4.5.6, extended shut-in durations after fracturing appear to initiate gas flow more quickly and do not delay production. However, during the fracturing operations themselves, the more quickly each stage is treated, the larger the amount of gas will be produced in the first 30 days.

2. Fracturing fluid tends to penetrate into the near fracture tip region during early production. Potentially a large amount of water is therefore trapped in that region during early flowback, which causes a deviation between the field water production data and the simulation results.

3. The first 30 days of a gas production profile (curve shape) is mainly determined by the producing formation’s pressure gradient. The well that has a steeper increase in gas production and sees gas decline after peak rate is likely to be drilled in a higher pressure gradient zone.

4. All three damage mechanisms (capillary end effect, non-Darcy flow, and compaction effects) are present in the Cana wells, and well production could only be matched when all three mechanisms are included in the model. Capillary end effect has the biggest impact on gas rates during the first 30 days production.

5. The early time delayed gas production observed among the Cana wells was caused by the slow closure process of hydraulic fractures, and could be modeled by adjusting the bottom-
hole pressure (BHP) decline rate in the simulator. Not much difference exists across the five wells regarding the reasons for gas delay.

6. A working flowback model for the Cana Field has been proposed. This model can be used for history matching the production data recorded during the flowback operations and investigating the fracture responses and reservoir conditions. Although the software requires further improvements, the FAST Consortium clean-up simulator is recommended for the next phase development and future usage in the field.

5.2 Recommendations

In order to have higher gas production rates within the first 30 days of production, reducing the total time of fracturing all the stages is recommended.

In addition to making it have better computational efficiency and including natural fractures into the model (Charoenwongsa, 2011), the current cleanup simulator could be improved in the following ways:

1. Let the simulator have the capability to automatically optimize the grid settings for fracture propagation and flow simulation each time the inputs are changed by the user, especially the number and size of the grid blocks in the fracture length direction (x direction in the model).

2. Instability issues should be revisited with regard to the following scenarios:
   a. When a larger injection volume (with the same magnitude as the field stimulation practice), and/or a higher reservoir pressure gradient for deeper wells, and/or a lower reservoir matrix permeability is to be input;
   b. When the relative permeability curves of the reservoir matrix are to be changed by the user.

3. The sub-irreducible initial water saturation option is recommended to be included into the simulator.

4. Let the simulator incorporate the surface operations (for example, changing the choke size) into the simulations and allow the BHP’s profile to change as a function of time.

   It is recommended that this simulator be applied to other formation types and producing fields, and to fracturing practices using gelled systems. For the history matching studies, it would be helpful to obtain DFIT data, which can provide some information of the reservoir and will reduce
the number of non-fixed variables. Also the economic evaluation of flowback operation is recommended.
NOMENCLATURE

\[ D = \text{depth, ft} \]
\[ f_{pr} = \text{retained permeability factor, fraction} \]
\[ k = \text{absolute permeability, md} \]
\[ k_p = \text{permeability of proppant pack at closure, Darcy} \]
\[ k_r = \text{relative permeability of gas phase} \]
\[ K_{rw(S_{wmax})} = \text{water relative permeability at maximum water saturation} \]
\[ \text{NGL} = \text{natural gas liquids} \]
\[ p = \text{pressure of gas phase, psi} \]
\[ p_f = \text{fracture pressure, psi} \]
\[ p_i = \text{initial reservoir pressure, psi} \]
\[ p_r = \text{average reservoir pressure at one point during production, psi} \]
\[ S_{wi} = \text{initial water saturation} \]
\[ \text{Tcf} = \text{trillion cubic feet} \]
\[ v = \text{velocity, [L/t]} \]
\[ \bar{v}_D = \text{Darcy velocity of gas phase, [L/t]} \]
\[ \bar{w}_f = \text{average fracture width, [L]} \]

**Greek Letters**

\[ \beta = \text{non-Darcy flow coefficient of gas phase} \]
\[ \phi_f = \text{porosity of proppant bed} \]
\[ \gamma = \text{density times gravitational acceleration for gas phase, [M/(L^2t^2)]} \]
\[ \mu = \text{viscosity of gas phase, [M/(Lt)]} \]
\[ \rho = \text{density of fluid, [M/L^3]} \]
\[ \rho_p = \text{density of proppant, [M/L^3]} \]
\[ \sigma_c = \text{closure stress, psi} \]
\[ \sigma_{h,min} = \text{minimum horizontal stress, psi} \]
\[ \sigma_n = \text{net stress at one point during production, psi} \]
\[ \sigma_{ni} = \text{initial net stress, psi} \]
Operators
\( \nabla = \) gradient operator
\( \frac{d}{dx} = \) spatial derivative

Subscripts
m = matrix
f = fracture
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