HYDRAULIC STIMULATION OPTIMIZATION OF THE PERMIAN BASIN'S LOWER SAN ANDRES RESIDUAL OIL ZONE

By

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HYDRAULIC STIMULATION OPTIMIZATION OF

THE PERMIAN BASIN'S LOWER SAN ANDRES

RESIDUAL OIL ZONE

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Abstract:

The Permian Basin is a legacy field within North America that has over 85 years of production. When operating in a legacy field, it is not uncommon to operate near a well that could be fifty years old or older. Many of these older wells were constructed at a time when regulations for safety and environment were not nearly as strict as they are today. As these new fields are discovered and developed, it is critical during the development plan to ensure that older wells nearby do not create a hazard to the new well or the environment around them.

The primary target of this research is determining whether or not the stimulation plan for a new horizontal well in the San Andres Formation will impact the older wells in the section and optimize the production from the stimulation. In order to achieve both of these goals, GOHFER software was utilized to determine fracture length and production post treatment. Nearby wellbores were used to create a lithology profile for the fracture simulator. Adjacent wells targeting the same play were to mimic a pump schedule and create a production model that matched what the field was capable of. Various stimulation designs were generated in the GOHFER simulator and resulting production was analyzed.

After evaluation the optimum design, was recommended. The optimum design could both avoid any potential hazardous wells and optimize the production for the region.

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INTRODUCTION

1.1 Residual Oil Zone Description

The Residual Oil Zone (ROZ) is a high water cut oil zone within the Permian Basin that has started to be developed. The zone is undergoing exploration in Lea (NM), Yoakum (TX), Terry (TX), Andrews (TX), and Cochran (TX) counties. All of these counties and the ROZ play are located within the Central Basin Platform of the Permian Basin.

The Llano Estacado Field is located in Lea County, New Mexico, which is considered the north western portion of the ROZ field. A local operator that was involved with this study is currently developing this field. The first well will be located in the northern section of the Llano Estacado Field. The target zone is Lea County, New Mexico. The one mile lateral well will be drilled from the north to the south end of the section at a target true vertical depth (TVD) of 5120'. Figure 1 depicts a general outlay of the Permian Basin, the San Andres Unit that will be targeted in north of the Capitan Reef (Shown with a dotted circle in Figure 1).

The Permian Basin is one of the most prolific hydrocarbon basins in North America. The ROZ play is located in the San Andres Stratigraphic Unit, which is a section of the Guadeloupian Series of the Permian system as seen in Figure 2. The San Andres unit accounts for over 30% of the Permian Basin's cumulative production and holds an estimated 40% of the Permian Basin's original oil in place (OOIP). (Koperna 2006)

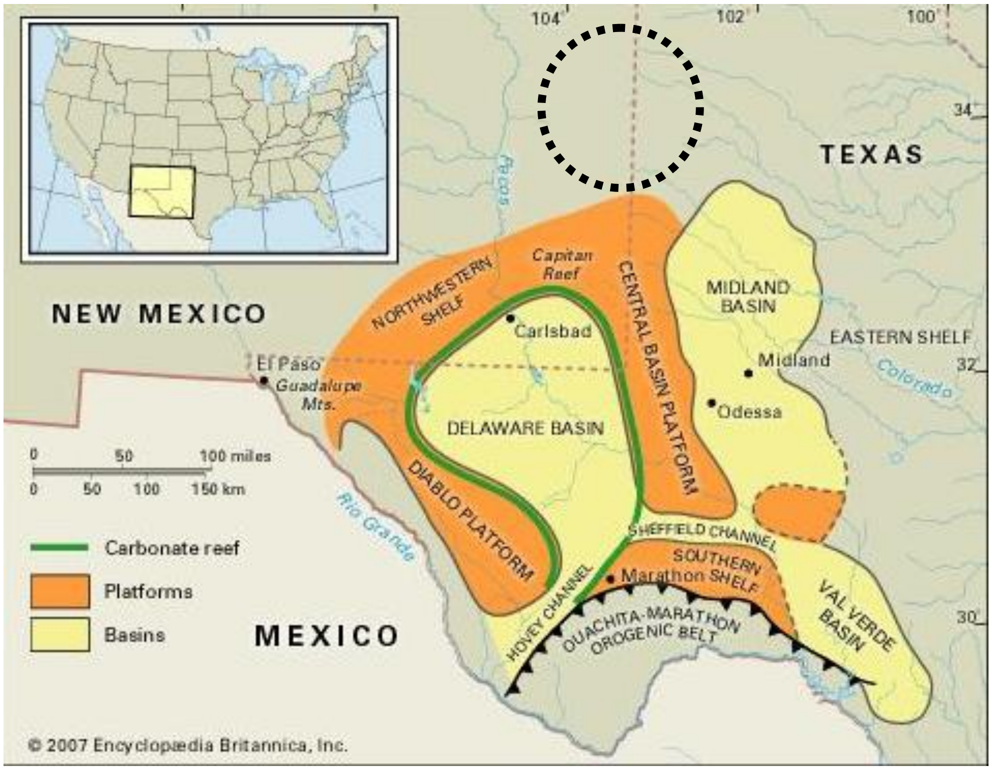

Figure 1: Geographical location of Permian Basin (Britannica 2007)

The ROZ is a unique zone because previous exploration in the zone has been limited. The ROZ is located directly below the main pay zone (MPZ). The MPZ is what has been conventionally produced over the last eighty years. There is a direct oil-water contact line that separates the ROZ and MPZ. As seen in Figure 3, the MPZ will typically have oil saturations of 70-100%, whereas the ROZ will experience oil saturations of 5-30%. In the past, operators only developed the MPZ because the ROZ was considered uneconomic. With the technological development of horizontal drilling, hydraulic fracturing, and efficient salt water disposal wells, the economics have improved to the point where the ROZ play has become economically viable.

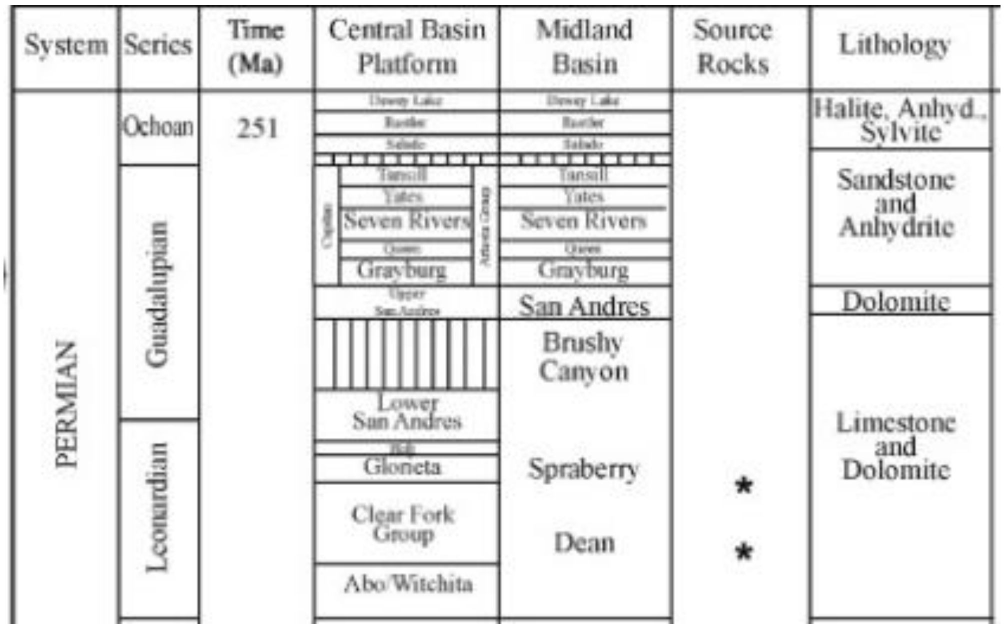

Figure 2: San Andres Deposition within the Permian Basin (Engle 2016)

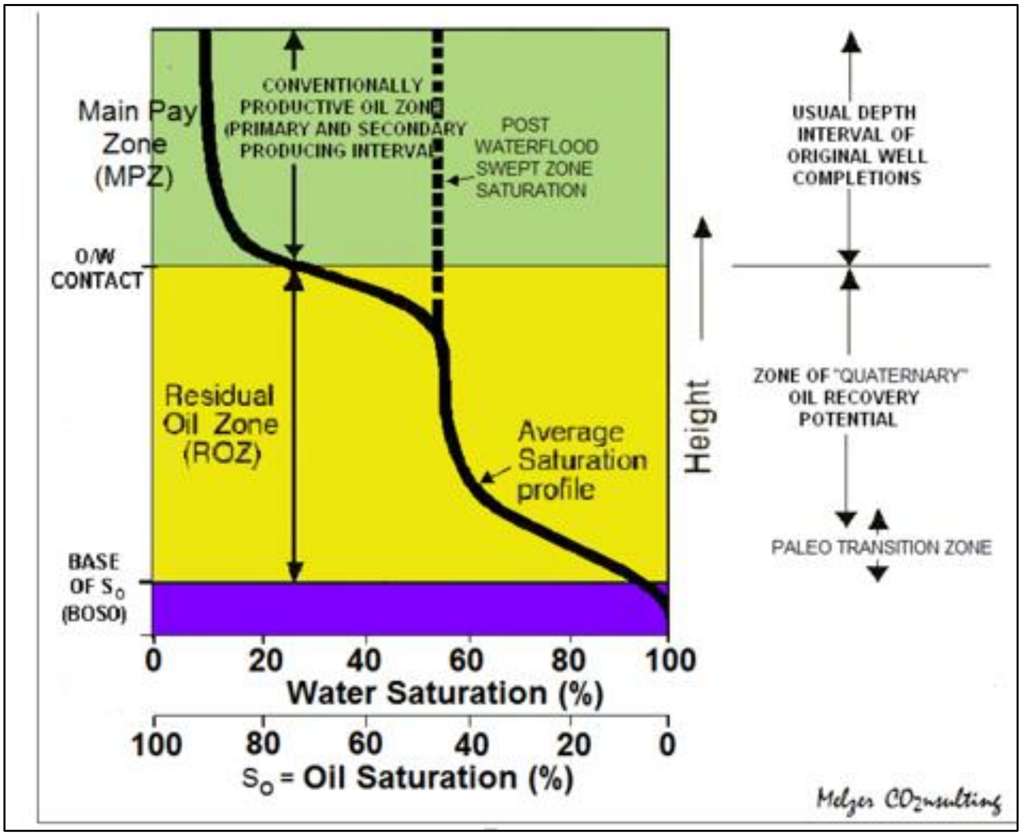

Figure 3: Oil saturation profile for residual oil zone (Koperna 2006)

1.2 Objective and Approach

As seen in Figure 4, within the area that the first well will be drilled, there are currently eight vertical wells that were previously drilled. Of these eight wells, two are still producing, and six have been plugged and abandoned. All of these wells were originally drilled between the late 1950's to the early 1970's. The depth of the previously drilled wells ranges from 8,000' to 11,000'. In an unusual event that occurred in 2004, an operator in the Permian Basin filed for a C101 on three of the six plugged wells, but no further documents were filed. A C101 is an application for re-entry in previously plugged wellbores. Since the operator had filed C101s but nothing more, it was inferred that they had not tried to reopen the plugged wells. Upon field inspection, it was quite evident that the wells had seen some activity, so the quality of the plugging and cement was uncertain. This called for a highly specialized hydraulic fracture design that would run a low risk of impacting the potentially reentered wells, but optimize the production capabilities of the well.

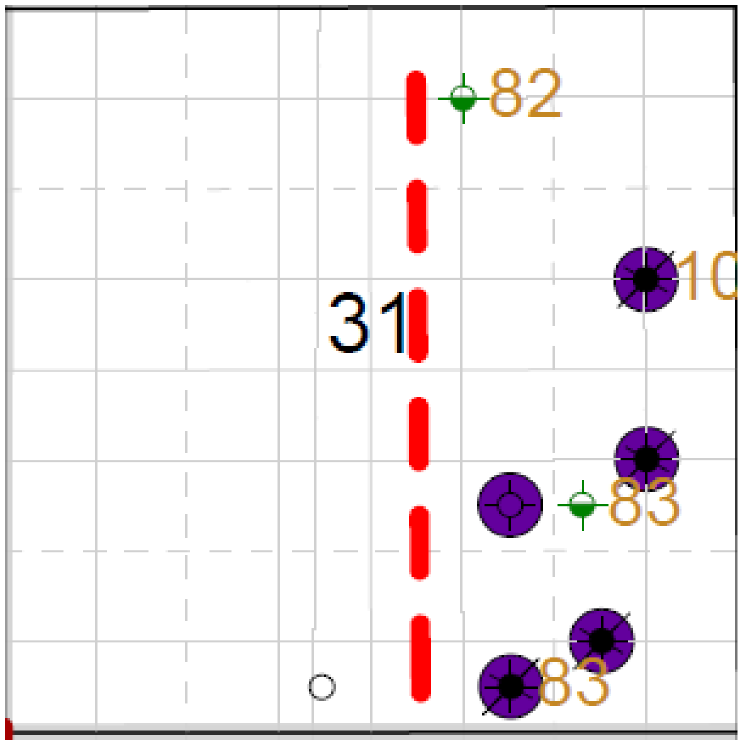

Figure 4: Location for proposed horizontal Well J prospect (red dotted line) with vertical wells in section locations

In order to achieve the goal of this project, a fully coupled 3D simulator and reservoir model would be needed. A Grid Oriented Hydraulic Fracture Extension Replicator (GOHFER) software fulfilled this need. With the use of a 3D simulation software, hydraulic fracture designs can be input into the program and simulated. The simulation results give an estimated fracture length and estimated production values correlated to each individual fracture design. With GOHFER, different designs can be successfully simulated and analyzed. The analysis will determine if the fracture will impact nearby wellbores as well as determine the most economically fruitful design.

CHAPTER II

LITERATURE REVIEW

This section of the study summarizes previously documented information on the ROZ San Andres formation and technical hydraulic fracturing information that can be applied to the well of interest. The information includes highlights and main findings to date, and sets a baseline for the comparison criteria that will be covered in a later section.

2.1 Hydraulic Fracturing Models

Current hydraulic fracturing models use an in-situ stress field with a high pressure injection to simulate fracture propagation. Given various fluid and solids during injection, these geo-mechanical models calculate fracture geometry as a function of injection method. Older geo-mechanical models used a two dimensional model that would assume a constant height as the fracture propagated. As the technologies for these stimulation models have improved, they have been accepted by the oil and gas industry and are used as fundamental tools when designing exploration jobs.

This study uses GOHFER® (3D Grid Oriented Hydraulic Fracture Simulator), a fracturing simulation software, to do reservoir simulation. The software is a solution for hydraulic fracture design, evaluation, and optimization. GOHFER integrates the handling of digital log data to produce horizontal and asymmetric fracture modeling that includes complex reservoir geometry. The software can then be utilized to assist operators in boosting well performance while lowering the capital expenditures required to complete a well.

GOHFER's grid oriented software generates a regular, planar grid structure in an x, y and, z plane that describes the reservoir rock and fluid properties similar to what a reservoir simulator would create. Various calculations such as elastic rock displacement and fluid flow solutions are ran in conjunction with each other as the simulation is processed. The "state variables" such as fluid composition, fracture width, pressure dependent leak-off, viscosity, etc. are defined at each node in the grid structure at each time interval.

2.1.1 Fracture Geometry

GOHFER's laboratory and field observations have concluded that rocks fail in both tensile and shear mode. These observations have been confirmed through micro-seismic studies throughout various types of rock. The fail in shear theory is the primary assumption used in creating fracture geometry within GOHFER software (GOHFER 2016). Laminated rock systems with high modulus contrast have a higher shear potential. The GOHFER software acknowledges the rock mechanical properties and approximates the fracture geometry by allowing the fracture propagation to vary by rock layer and allowing geo-mechanical properties of that particular layer define the models fracture geometry.

2.1.2 Data Input

The GOHFER software imports digital log data directly and assigns rock property values, rock elastic properties, porosity, and permeability to construct the model for fracture geometry. An internal stress profile is calibrated based on logs and lithologic assumptions to observe closure stress and pore pressure during the design and evaluation process of modeling fractures (GOHFER 2016).

2.1.3 Data Output

Using local values of porosity, permeability, fluid viscosity, pressure differential, and time of exposure GOHFER computes leak-off at each point of the fracture's surface (GOHFER, 2016). Changes in fluid velocity and proppant concentration will affect the fracture geometry. With that in mind, GOHFER automatics incorporates the effects of secondary shear fractures and determines the differences between fissure leak-off and matrix leak-off. The higher rate fissure leak-off impacts fracture geometry by causing slurry dehydration and a banking of proppant near the leak-off site resulting screen-out near the wellbore. These screen-outs result in short propped fracture lengths correlative to the perforation cluster receiving injection.

2.1.4 Production and Post Treatment Analysis

A Stim-Lab data base contains values for proppant conductivity at various temperatures and stresses. It also includes a clean-up model for gel damage associated with the fracture fluid and multiphase non-Darcy flow effects. The production and post treatment analysis within GOHFER uses these values when making well performance assumptions (GOHFER 2016). Other production models such as the Dynamic Drainage Area (DDA) have shown very similar production results with the single phase Agarwal-Gardner type curve model for finite-conductivity fracture production used in GOHFER (Clarkson et. al. 2015).

2.1.5 Alternative Hydraulic Fracturing Models

<u>Fracpro:</u>

Fracpro is a Pseudo-three-dimensional hydraulic fracturing model (Fracpro 2011). This practical model was first proposed by Settari and Cleary in 1986. The model is based on a 3-D lumped fracture model that can have minor alterations on the fracture shape and geometry through geologic inputs such as fracture toughness, lithologic stress profiles, and leak-off. These values are multiplied into the grid block system and create the geometric shape of the simulated fracture. Fracpro's Pseudo-3D model is defined by using equations for fluid flow and crack opening through the main body of the fracture and couples a design that determines fracture growth in the vertical direction at cross sections through the outlaid grid structure.

<u>MFrac:</u>

MFrac is a three dimensional fracture model that models both the vertical and horizontal propagations of the fracture during the modeling process (Meyer 2012). The model approaches a Perkins-Kern-Nordgren (PKN) fracture model which essentially means constant height type geometry due to the large height and length aspect ratios set in the model (Wu 2014). In the circumstance of no confining stress or differential between rock moduli in the model, the fracture will take a vertical radial shaped fracture geometry. MFrac is considered to be between a pseudo 3D and fully 3D type of model, because it accounts for various rock properties that effect proppant transport and thus fracture geometry.

Stimplan:

Stimplan uses a rigid finite element method to create a fracture throughout a single plane. Stimplan's software uses a fully numerical computation for fluid flow and proppant transport calculations that solves equations to determine fracture width and propagation throughout a formation with varying rock strength qualities. The fracture width is calculated using a 3-D function of elasticity, and this function is applied to all of the gridded pressure points within the fracture zone. Using this calculation a complex fracture geometry can be effectively simulated and measured (Stimplan 2010).

2.2 Description of Modeling Software

2.2.1 Simulation Software

The hydraulic fracture simulator chosen for this project was GOHFER®, an acronym for Grid Oriented Hydraulic Fracture Extension Replicator. A grid structure creates the reservoir rock characteristics for GOHFER, which allows for vertical and horizontal variations in rock and fluid properties. GOHFER was developed and maintained by Dr. Bob Barree and Barree & Associates.

2.2.2 Parameter Range of Simulations

For this study only one type of reservoir structure was evaluated. The premise of this work was to optimize the hydraulic fracture design for one well within the San Andres ROZ play and assume that the wells within the region would have similar reservoir characteristics. Based upon prior experience, it is known that north-south horizontal wells will display transverse fracturing traits. One metric that was pivotal in evaluating the stimulation's performance was the Dimensionless Fracture Conductivity (FCD). FCD was introduced by Prats in 1961 and is the ratio of fracture conductivity and fracture width versus the reservoir conductivity and fracture half length. Figure 5 displays the calculations that are used in determining FCD. The reason FCD was so pivotal in this is because production after stimulation is a measure of how effective the stimulation job was. Since only one reservoir matrix was evaluated, all geo-mechanical properties stayed constant. The only way to effectively enhance production was to increase the FCD for each fracture and achieve as much Stimulated Reservoir Volume (SRV) as possible before diminishing returns were realized. Each design would result in altered fracture lengths and fracture conductivities. These values played a pivotal role in selecting the optimized stimulation design.

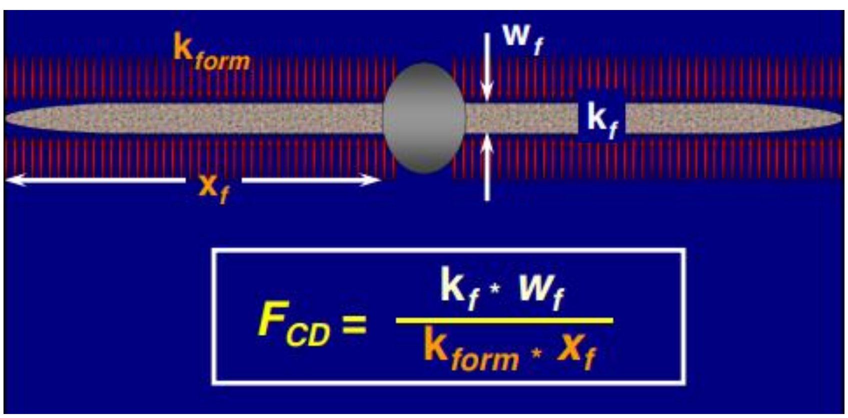

Figure 5: Dimensionless Fracture Conductivity where K_f is fracture permeability (mD), w is fracture width (ft), K_{form} is formation permeability (mD), and X_f is fracture half length (ft).

2.3 Residual Oil Zone Production Mechanics

Residual oil zones are not exclusive to the Permian Basin. In fact, ROZ exploration has been successfully implemented in plays such as the Hunton Formation in central Oklahoma. Residual oil zones are typically not targeted during conventional exploration because the water cut makes the well uneconomical. Due to petro-physical properties, as the water saturation increases, oil mobility within the formation decreases. At a water saturation of about 70%, oil is considered immobile. Figure 6 depicts the fraction flow of water compared to the saturation of water within the formation.

In order to produce the ROZ, it takes persistence on the operator's part. When an ROZ well is developed, it is not uncommon to at first have 100% water production. However, as the well is produced or "de-pressured," the water saturation within the pore space is reduced and the oil saturation increases (Figure 7). As the water saturation is decreased in the pore space, the fractional flow of oil increases and oil production begins, as seen in Figure 8.

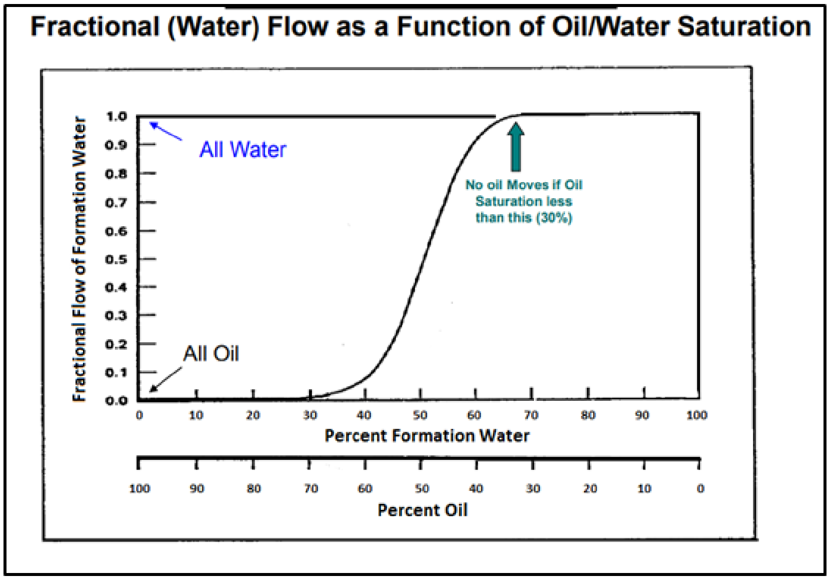

Figure 6: Fraction flow of water compared to the saturation of water within the formation (Melzer 2016)

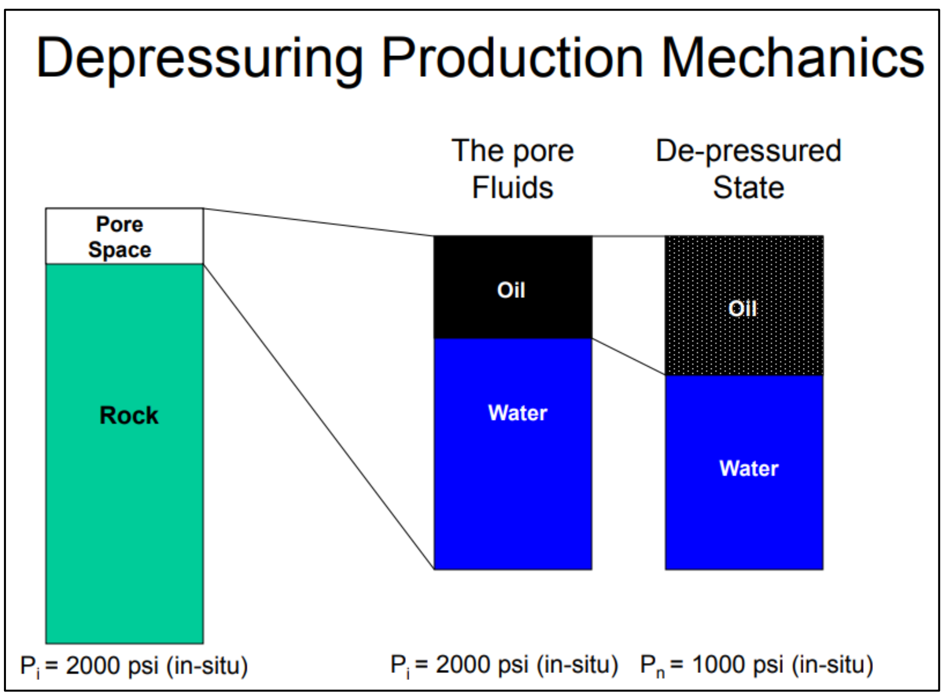

Figure 7: Initial production in ROZ increasing oil saturation (Melzer, 2016)

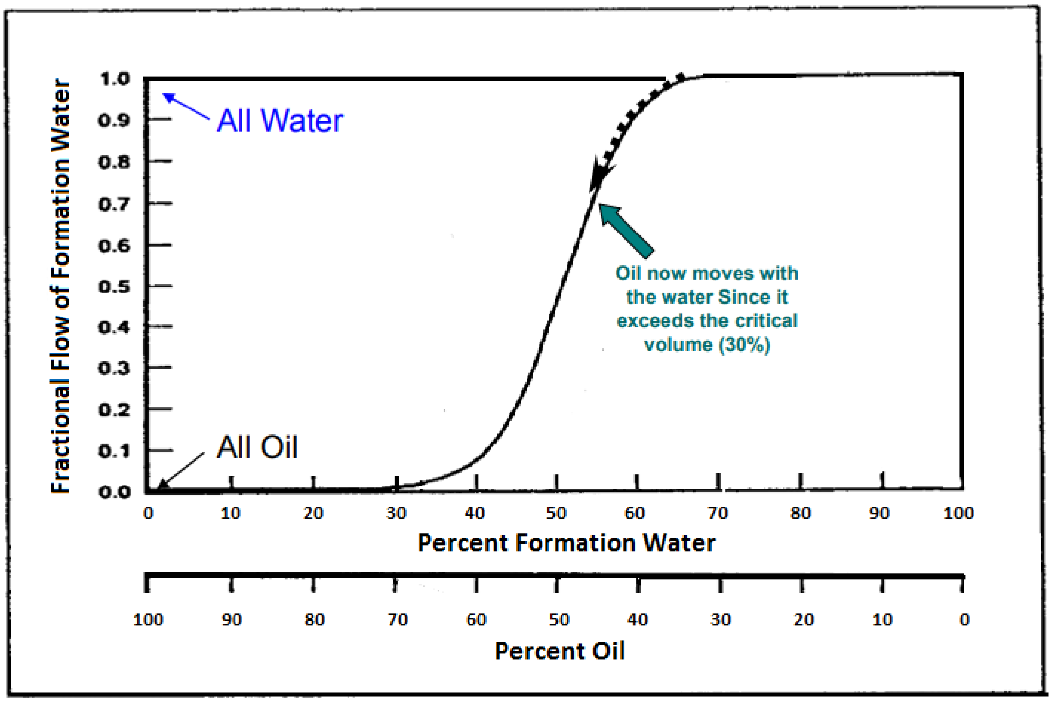

Figure 8: Water saturation decreasing resulting in increase of oil fractional flow (Melzer 2016)

During a de-pressurizing upper residual oil zone (DUROZ) study (Melzer 2016), 11 wells were analyzed to determine when oil first started moving as pressure was incrementally reduced. Figure 9 shows the results from the DUROZ study. It is important to note that for most wells, the original formation pressure must be reduced by nearly half in order for oil production to begin. It is also important to note that this de-pressurization can take up to a month before oil cut is realized, so it is important for operators to have adequate water disposal capabilities.

DUROZ Case Histories
Pressure Characteristics

DUROZ WELLS: YOAKUM CO., TX

	Well	Initial Intake Pressure	First Oil Cut Intake Pressure	Lateral Length	Day	Days Until First Production	Ave BOPD since 1st Oil
1	What A Melon 1H	1745	1225	1 mile	393	26	166
2	Well #2	2120	1315	1 mile	378	31	202
3	Well #3	1700	1270	1 mile	195	6	203
4	Well #4	1975	1090	1.5 mile	170	32	313
5	Well #5	2030	1200	1 mile	151	22	126
6	Well #6	2225	1150	1 mile	122	32	243
7	Well #7	2053	1260	1 mile	83	25	228
8	Well #8	2110	1635	1 mile	42	30	142
9	Well #9	1820	No Oil Cut Yet	1.5 mile	20		
10	Well #10	2040	No Oil Cut Yet	1.5 mile	20		
11	Well #11	1750	No Oil Cut Yet	1 mile	1		

Figure 9: DUROZ 11 well study of pressure reduction until first oil cut is realized. (Melzer 2016)

In summary, all of the oil within the ROZ is immobile at the beginning of production. As water is removed and the reservoir depressurizes, oil and gas begin to occupy a greater percentage of the pore space. Some of the oil becomes mobile once water saturation is decreased enough and moves into the flow stream of the reservoir rock. Water dominates all the production for the period of time until the pressure falls below a threshold level. The play works best in oil wet or mixed wet rocks that allow the water to flow easily during the beginning of production. This flow type can be modeled with relative permeability curves. This play requires ample water disposal capabilities and persistence by the operator to continue to produce the large volume of water required in order to see hydrocarbon production thereafter.

2.3.1 Enhanced Oil Recovery Mechanics

Source water for the play is critical. In most conventionally produced assets, Enhanced Oil Recovery (EOR) is generally implemented through the use of water floods or CO2 floods for tertiary recovery. The San Andres Formation is unique because the formation has an outcrop near Six Mile Hill, New Mexico. Six Mile Hill is located six miles west of Roswell, New Mexico, at the base of the Capitan Mountains. The San Andres down dips in an east to southeast direction primarily, so the water runoff from the mountains slowly deepens into the San Andres formation. This unique phenomenon creates a natural water flood effect in the ROZ section of the San Andres Formation. Figure 10 depicts the fairways that are created from San Andres outcrops, and where the source water is created.

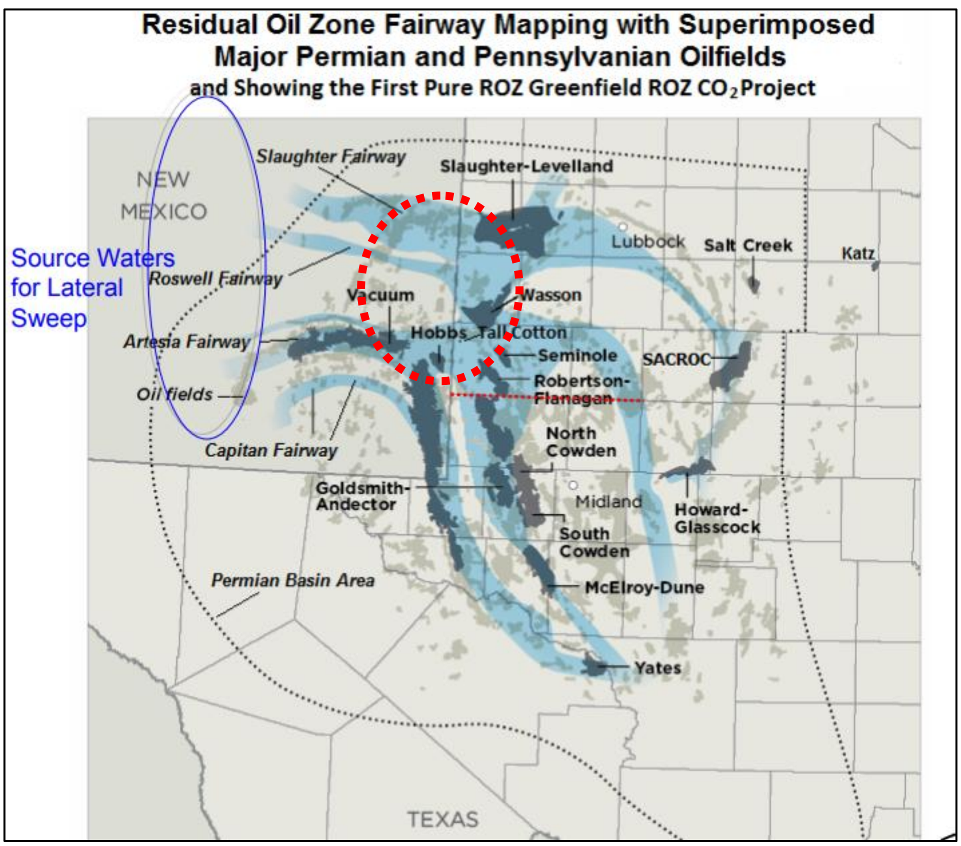

Figure 10: San Andres outcrop near Six Mile Hill (Rassenfoss 2017)

2.4 Horizontal Drilling and Hydraulic Fracturing

Most wells drilled that look for water or natural resources are vertically drilled wells, meaning that they are essentially a straight hole drilled directly into the earth. In the mid 1900's a new phenomenon was discovered, which was the advent of horizontal drilling. As seen in Figure 11, this process allows drilling rig operators to turn the drill bit in any direction and allows the well to be drilled in a horizontal plane once the target depth is reached. Horizontal drilling allows operators to hit targets that cannot be reached by vertical wells, drain from larger reservoirs using a single surface pad, and develop what would have been sub-economic vertical prospects into lucrative fields.

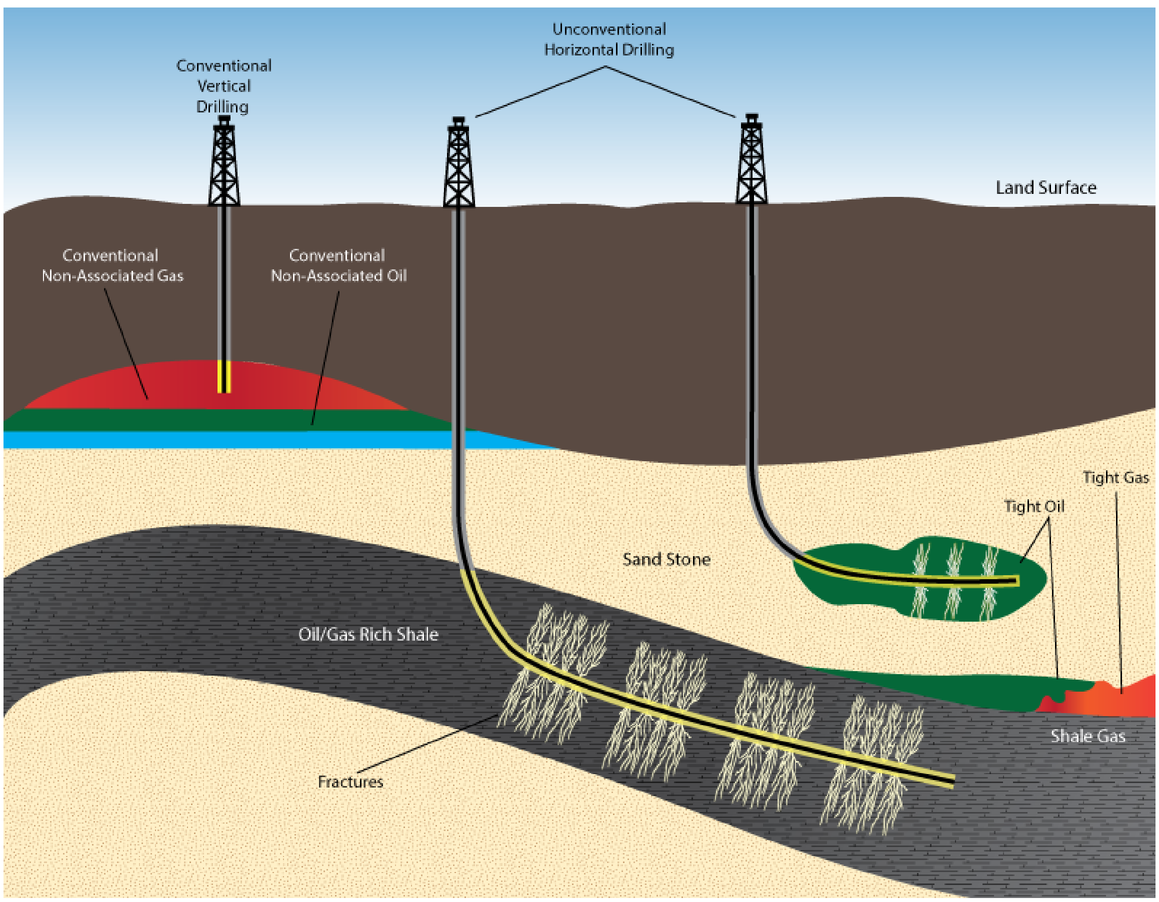

Figure 11: Horizontal versus Vertical Drilling Practices (Sanchez, 2017)

Horizontal and directional drilling are achieved through the use of Rotary Steerable Tools (RSS), whipstocks, and steerable motor assemblies. As the hole is deepened during the drilling process, Measurement While Drilling (MWD) tools are used to allow the operator to gain information on the direction the drill bit is moving. Surface samples are taken and a geologist and mud logger analyze the rock cuttings to ensure that the zone of interest is still being penetrated.

Hydraulic fracturing is a well stimulation method that is used in reservoirs with low permeability to enhance oil and gas recovery. In order to stimulate a well, typically a fluid and sand mixture is pumped at high pressures and rates into a perforated casing string. The high pressures tear the formation, and the split that occurs is called a fracture. The pressure from the fracturing fluid keeps the fracture open while the job is being pumped, and when the job is completed the proppant that was in the fluid will hold the fracture open during the production phase. A successful stimulation treatment is indicated by an immediate change in production rate, which is comparatively higher than that of an unstimulated well. Figure 12 demonstrates how a stimulated reservoir improves production.

Hydraulic fracturing was first tested on a well in the Hugoton gas field of Grant County, Kansas in 1947. During the 1950's, hydraulic fracturing became commercially used. The first multi-stage hydraulic fracturing job in a horizontal well was completed in 1987, and in the 30 years since, the technology and techniques have continued to change and improve production (Manfred 2015). As hydraulic fracturing has developed and improved, many oil and gas assets that were not commercially available due to their low permeability qualities are now widely developed and high volume producing assets. Figure 13 displays the general equipment needed in order to hydraulically fracture a reservoir.

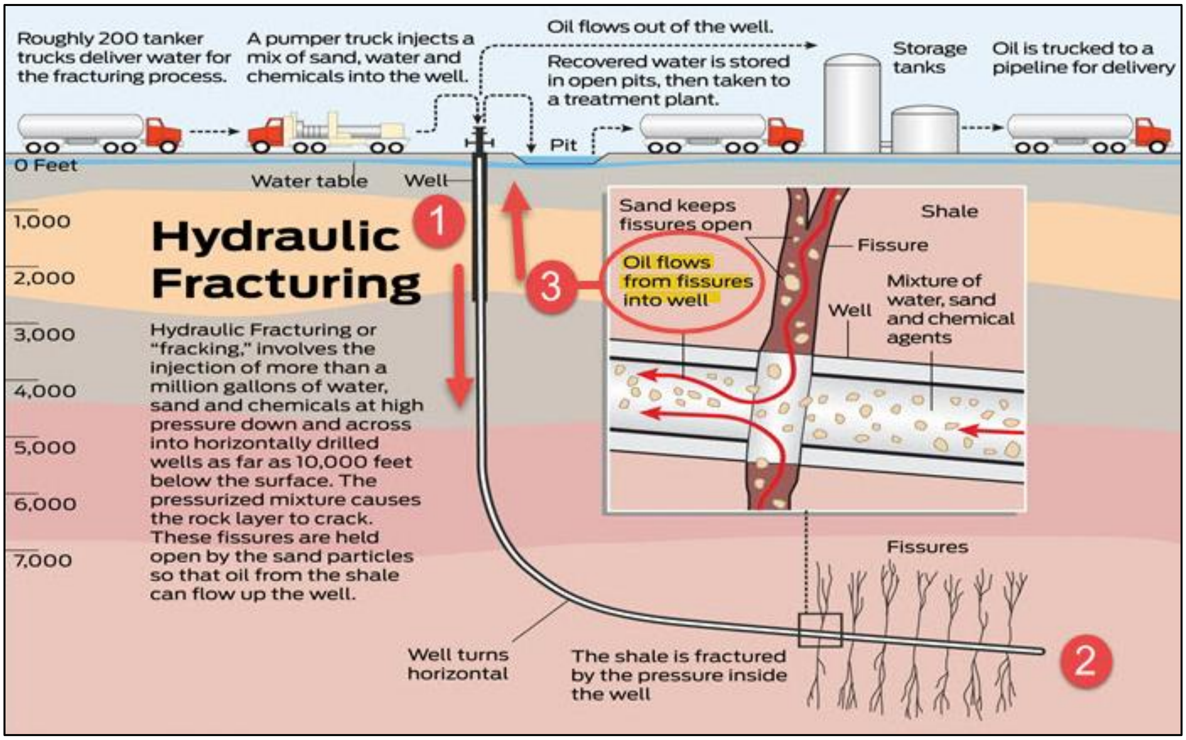

Figure 12: Fracking Information (Shalestuff 2017)

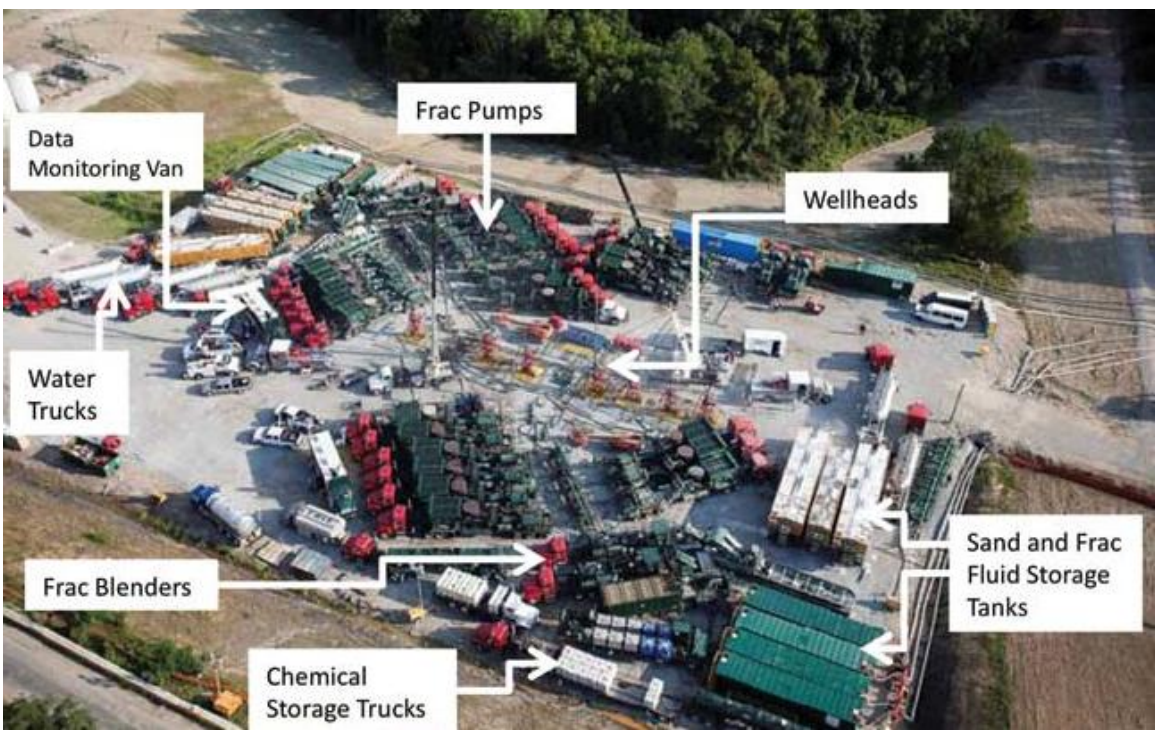

Figure 13: Location Equipment for Fracturing Treatment (Suchy 2011)

Each formation will fracture differently, so stage design and volumes differ from job to job or company to company. As a general rule, stimulation jobs follow a general design as follows:

1. Clean Up Stage: Diluted hydrochloric acid is bullheaded down the wellbore to clean up debris in the wellbore and open up packed off perforations. This allows the fluid to create easier pathways to the reservoir.
2. Breakdown Stage: Frac fluid is bullheaded following the acid at higher rates and pressures to create a fracture into the formation.
3. Pad Stage: Fluid continues to be bullheaded down the well at a rate and pressure that will keep the fracture open while extending the fracture wing out into the reservoir.
4. Proppant Stage: A slurry of sand and/or ceramic proppant is added to the fracturing fluid and pumped down hole, which will keep the fracture open and allow reservoir fluids to flow through the generated network.
5. Flush Stage: A fluid is pumped without sand that will displace the sand from the wellbore to the formation. Typically just enough fluid is pumped to fill from the top perforation to the wellhead so over-displacement of the sand does not occur, but the wellbore will be clear for a plug to be pumped down and set for the next stage.

2.5 Comparison Criterion

Efficiency of a stimulation job is determined by three primary variables: rate, recovery, and economics. This section discusses these variables in detail, as they are used to evaluate and analyze the proposed stimulation designs of this study.

2.5.1 Initial Production (IP) and 1-3 Year Production

Initial Production (IP) and 1-3 year production analyses were both used for evaluating the stimulation performance, but are evaluated independently. The IP rates give an insight on the well's production capabilities. The capabilities are created by reservoir mechanics and the quality of the stimulation job. The IP is not reflective of longer term recovery and final well value.

1-3 Year cumulative production gives insight on the payback period expected and longer term production forecast for economic evaluation. The 3-year limit was set because this field is a new development, and during the course of the study the longest a well had produced in the area was 33 months. With this in mind, a production model was ran only for a one year period to ensure that the model results could also be replicated in the field.

2.5.2 Estimated Ultimate Recovery

Estimated Ultimate Recovery (EUR) is a common metric used within the oil and gas industry to determine the worth of a company or well prospect. EUR is determined by estimating the quantity of reserves that can be drawn from a reservoir by a well until the end of the well's productive life.

For this study, EUR was not set at a particular year. Many EUR estimates are set for a 30 year period, but this does not reflect accurate total recovery. Many wells are plugged and abandoned when the rate that they are producing at does not make the well economically feasible to produce. For this study a conservative rate value was taken for a final producing rate of 10 Barrels of Oil Per Day (BOPD). Simply, this means that at below 10 BOPD, the production revenue does not justify the overhead costs of keeping the lease running.

2.5.3 Net Present Value (NPV) and Internal Rate of Return (IRR)

When evaluating an oil and gas well, the concept that higher recovery reflects higher profit is inaccurate. The amount of capital that is spent in order to get the production is important because it reflects a return on investment. Along with the Capital Expenditure (CAPEX) and Operational Expenses (OPEX), a time value is also associated with the economics for a well development.

The idea that capital received or spent in the future is not worth the capital gained or spent today is known as the concept of 'time value,' and is commonly referred to as 'discounted cash flows.' A Discount Rate (DR) is assigned to annual time periods that discount future cash flow values into present values. The higher the DR, the less the future values are worth in terms of present value. Once the discount rate is set a present value can be determined by estimating the future value of future cash flow and discounting it by the set discount rate and the time period at which the cash will be received.

Net Present Value (NPV) is a measure of a project's value in present value. NPV is used in capital budgeting to analyze the profitability of a projected investment or project. To calculate the NPV, it is simply a summation of all future values discounted to present value, deducting the capital expenses.

Internal Rate of Return (IRR) is a metric used to determine what discount rate will set the net present value of a project to zero. As mentioned previously, the higher the discount rate, the greater future values are impacted. Since most of the future cash flow in an oil and gas well are positive, a higher IRR reflects a more lucrative project. IRR is a good metric to use when comparing projects of vastly different economic stature because it normalizes capital value into a direct comparison on return on investment format. Figure 14 depicts how an increased discount rate lowers the net present value, at the percentage discount rate where the net present value is $0 the IRR has been determined. Table 1 displays the economic input for the Well J prospect that were needed in order to determine NPV and IRR.

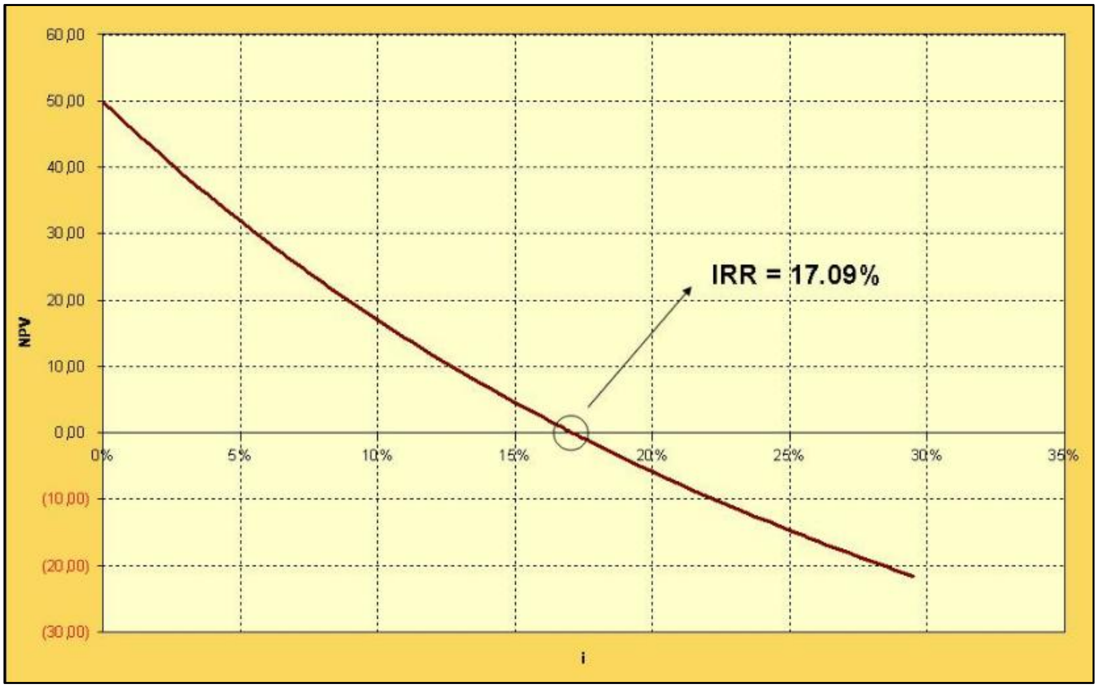

Figure 14: Impact of discount rate on Net Present Value of a project and IRR determination (Lumenlearning 2017)

Table 1: Economic Inputs for ROZ calculations

Economic Inputs	
Parameter	Well J
Oil Price (WTI)	45.00 $/BBL
Gas Price	3.00 $/Mscf
Discount rate	10%
Drilling Costs	1.1 MM$
Completion Costs	Varies on completion design
Operational Expenses	7500 $/month

CHAPTER III

FIELD DESCRIPTION

3.1 Geologic Background and Available Information

The San Andres formation has had over 50 years of exploration and research conducted on the play. To acquire information, well logs that are through the zone of interest can easily be accessed through state funded websites such as the New Mexico Oil and Gas Conservation District (NMOCD). Previous depositional studies have confirmed that the fracture plane for the region are nearly true east-west fractures (Hills 1970). This dictates a transverse fracture system for Well J's north-south wellbore. Additional cores and drill cuttings reports allow for an accurate rock type characterization. State mandated production reporting assist in proposing decline curves that can be replicated within decline curve analysis to better anticipate the production for a given well.

3.2 Original Exploration

"What was envisioned only as a commercial exploitation strategy via EOR methods (particularly CO_2 EOR) made a huge turn in 2013. The development of horizontal drilling and well stimulation advances in shale reservoirs over the previous two decades led to the hypothesis that if these methods worked+ in ultra-low permeability shales, why couldn't they work in low permeability carbonates? To test that hypothesis, Manzano, LLC. drilled and hydraulically fractured a 4500' lateral in the San Andres formation in Lea County, New Mexico with the idea that the reservoir would be low permeability. Production of 2000+ barrels of water per day changed that view.

They continued to produce until the reservoir pressures dropped approximately one-third and oil and gas began to be produced" (Melzer 2015).

3.3 Recent Treatment and Production

It is important to note that the San Andres ROZ is split into two targets, north and south (Figure 15), and this study targets the northern zone.

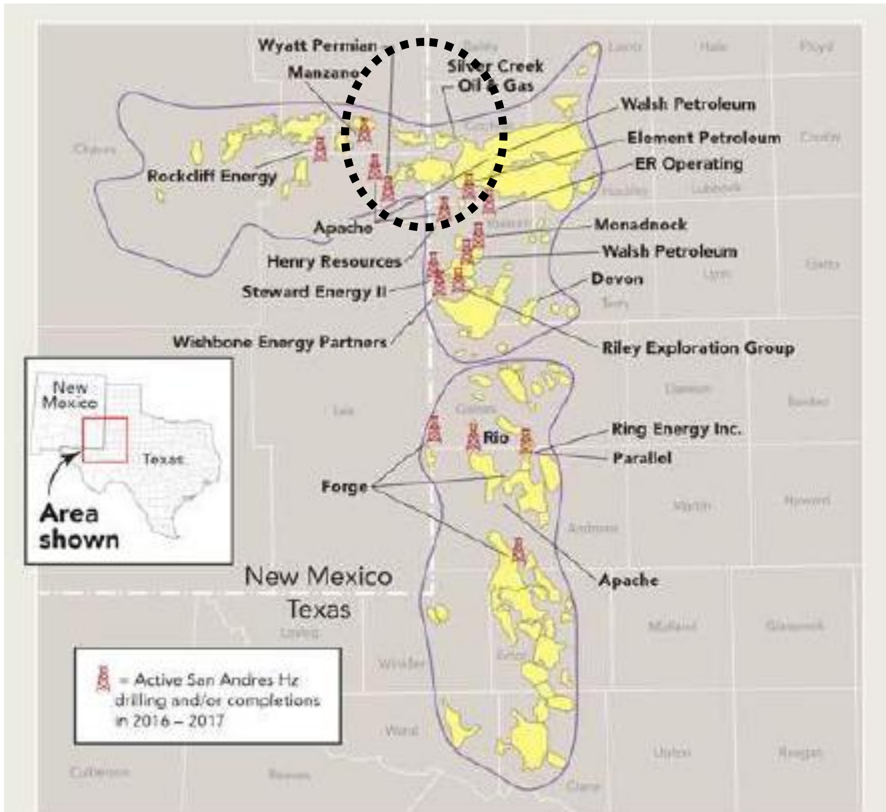

Figure 15: North and south ROZ layout with active operators (TMG Consulting 2017)

TMG Consulting (2017) performed a statistical analysis on all the wells in the northern region and created a distribution showing their peak monthly production. As seen in Figure 16, the mean for the play was roughly 270 barrels of oil equivalent per day during the peak month.

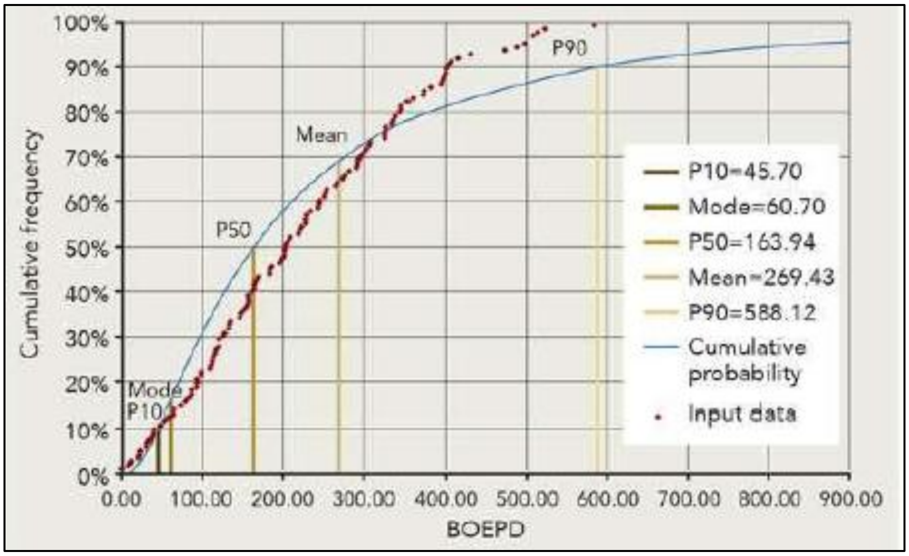

Figure 16: Northern ROZ average daily peak month distribution (White 2017)

Table 2: Northern ROZ fracture designs (White, 2017)

Fracture Design	
Lateral Length (Miles)	1-1.5
Frac Stages	15 to 30
Sand per Stage (Pounds)	135,000
Stage Length (Feet)	225-800
Proppant Volume per foot (Pounds)	2MM to 3 MM
Frac Pump Rate (Barrels per minute)	50 to 75
Proppant Type	40/70, 30/50/, 20/40
Gel Type	Linear, Crosslinked

3.4 Economic Overview

Economics is the driving factor in determining whether or not a play should be developed. In 2016, drilling and completions costs for wells in the ROZ were \$2.3-\$2.4 million for 1 mile lateral wells, and $2.8-$2.9 million for 1.5 mile lateral wells (Weeden 2017). Table 2 displays the completion metrics used when projecting the costs for the play. The play exhibits a vast amount of water production, so the need for cheap water disposal is pivotal. Local operators in the region have a $0.10 to $0.25 per barrel disposal cost associated with their water production. In order to achieve a low disposal cost, operators are drilling their own salt water disposal (SWD) wells into the Devonian Formation and then building their own collection system (White 2017). The ROZ is appealing for many operators because it is not just another high cost unconventional play. Many of the Permian targets require high capital costs for high yield returns. The private operators that are more concerned with return on investment find the ROZ play to be just as competitive as unconventional plays.

White (2017) ran an economic analysis on an average well for the region and found that even with depressed oil prices, the San Andres economics make this play incredibly lucrative, especially for independent operators. Independent operators thrive in these plays due to their low lease operating costs compared to major players. Tables 3 through 6 list the economic inputs used during the ROZ evaluation.

Table 3: Single Well Economics Well Assumptions (White, 2017)

Well Assumptions	
Location	Andrews County, TX
Formation	San Andres
Completed Well Cost	$2.6MM
Lateral Length (Miles)	1.5
Royalty	25%
%Oil	90
%Gas	10

Table 4: Single Well Economics Production and Reserve Assumptions (White, 2017)

Production and Reserve Assumptions	
B Factor	1.25
Initial Decline	85%
Gross EUR (MBOE)	686.7
Net EUR (MBOE)	515.0
IP (BOE/D)	650
Discount Rate	10%
Net Present Value	$3.6MM
IRR	83%

Table 5: Single Well Economics Price and Operating Assumptions (White, 2017)

Price and Operating Assumptions	
WTI Oil Price	$45.00
Oil Realization Discount	-10%
Henry Hub gas price	$3.00
Gas Realization Discount	-5%
Operating Costs per BOE	$10.00
Annual Lease Operating Cost Escalation	3%
Production Tax Rate	5%

Table 6: Single Well economics internal rate of return scenarios (White, 2017)

IRR Scenarios					
WTI Oil Price	$45.00	$50.00	$55.00	$60.00	$65.00
IRR	83%	118%	160%	211%	272%

As seen in Table 6, as oil price increases in small $5 increments, the Internal Rate of Return IRR for the play increase dramatically. As oil price was decreased to $32.00/BBL, an IRR of 18% was realized. This price would reflect a breakeven price for most operators. It is important to note that these price projections neglect General and Administrative (G&A) costs and assume a low cost infrastructure development on a per-well basis.

CHAPTER IV

STIMULATION MODEL DEVELOPMENT AND HISTORY MATCHING

4.1 Model Development

To fulfill the goal of creating a reservoir fracture and production model, first a lithology profile must be built on the area of interest. This includes determining rock characteristics from known data and adding log profiles from adjacent wells when available as seen in Figure 17. The oval dotted line in Figure 17 indicates the minimum horizontal stress profile and a great potential for successful fracturing with anhydrate layers above and below the target interval from 5000' to 5140'. To create this lithology profile, a wellbore that was 861' southeast of the projected toe landing for the Well J prospect was used. The Adjacent well ran to a depth of over 8000' TVD, so the Well J zone of interest was covered. The adjacent well had Gamma Ray and Unscaled Neutron Logs, these logs were digitized and used as a reference well file in GOHFER to construct the reservoir grid. To ensure the rock type for the system was correct, a well drilled 7.5 miles south of the Well J prospect was cored previously, and those cores were in the zone of interest. An X-Ray diffraction (XRD) analysis was performed on these cores at the Noble Research Center in Stillwater Oklahoma, and the cores were determined to be nearly 100% dolomite. The XRD results can referenced in the appendix section.

After the known information from the area was input into the GOHFER software , the program will assume all other lithology characteristics that are common for a particular rock type. This leaves a window of error for the program, but with the known information the window become significantly smaller. When the formation matrix, or "grid", is established, simulated hydraulic fractures can be ran through the program. Once a production model is created that replicates field production, different stimulation designs can be simulated and the production output from each design can be evaluated.

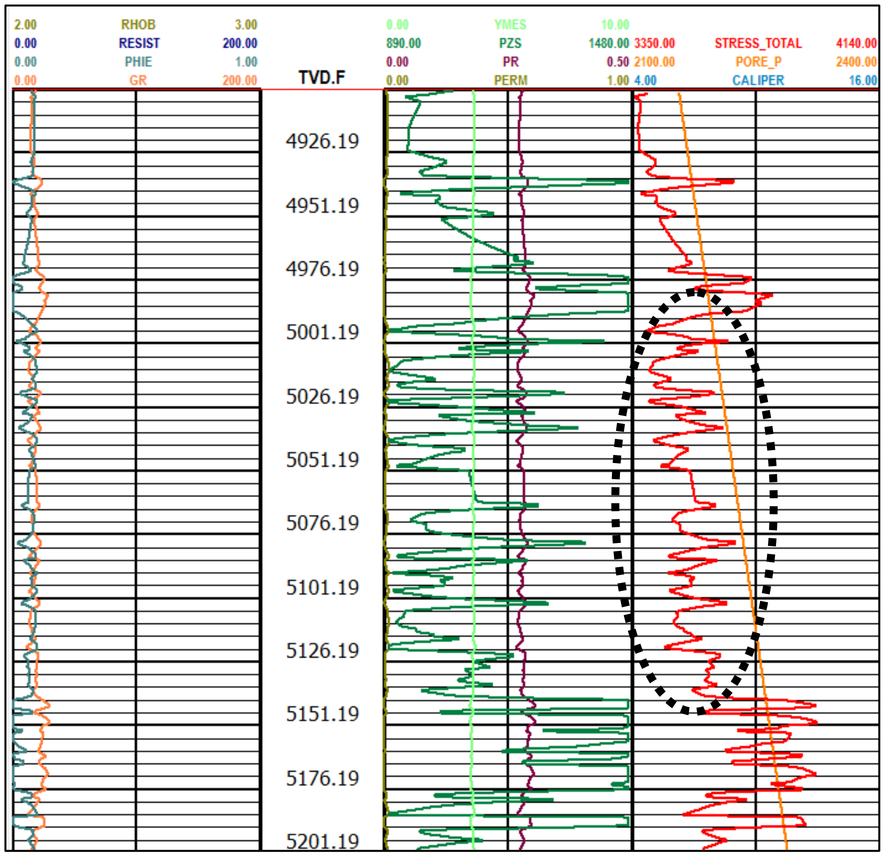

Figure 17: True Vertical Depth (TVD) stress profile created in GOHFER using input rock properties and adjacent well logs for correlation. (NMOCD 2017)

4.1.1 Input and Control Variables

The well of interest is a hydraulically fractured horizontal well with transverse fractures. In order to evaluate the performance of the stimulation, well properties and reservoir properties must be input into GOHFER software. The needed data includes well data, perforation data, stimulation data, reservoir data, production fluid data, and production model parameters.

Well data was input by downloading the well path profile into GOHFER. This well path profile contained casing string information and well direction. The reservoir data included a closed boundary reservoir that was 640 acres grid that did not have any competing wells in the section. The well was placed within the middle of the 150 foot pay zone with a lateral length of 4400 feet of potential stimulation options.

The reservoir was an oil, gas, and water mix as listed in Table 7. All flow within the fracture was assumed to be non-Darcy. The well was completed as a cased-hole completion, and perforations along the well bore would allow for a limited entry style of stimulation. Table 7 lists all constant input for the well for each case, and the altered stimulation design will impact the production thereafter.

The control variables for the production model assumed a means of artificial lift from the initial production. The wellhead pressure remained constant at 80 psi. The water cut for the well after the initial depressurizing period was assumed to be at 80%.

Table 7: GOHFER Simulation Input Data for ROZ Area

Reservoir Productivity		Well Properties	
Reservoir pressure (psi)	2230	Well orientation	Horizontal
Permeability (md)	0.0225	Perforation depth TVD (ft)	120
Porosity (fraction)	0.072	Perforation depth MD (ft)	2500
Water saturation (fraction)	0.8	Wellbore radius (ft)	0.325
Drainage area (acre)	1	Tubing ID (in)	2.441
Reservoir compressibility (1/psi)	1.22E-05	Un-stimulated skin	3
Bottomhole temperature (° F)	125	Wellhead temperature (° F)	70
Young's Modulus (Mmpsi)	3.613	Lateral vertical position	0.5
Formation thickness (ft)	150	Contributing lateral (fraction)	1
		Lateral length (ft)	4400
Reservoir Fluids		**Model Parameters**	
Fluid type: oil	Oil	Well control	Constant WHP
Gas specific gravity	0.63	Constant flowing surface pressure (psi)	80
Gas compressibility (1/psi)	0.00046	Water production	Constant Water Ratio
Gas viscosity (cp)	0.01699		
Oil specific gravity (API)	32		
Oil compressibility (1/psi)	1.38E-06		
Oil viscosity (cp)	1.4957		
Oil formation volume factor	1.2		
Water compressibility (1/psi)	2.82E-06		
Total viscosity (cp)	0.767373		
GOR (scf/stb)	800		

4.1.2 Output

After the reservoir characteristics and wellbore specifications are set in place, the performance of the hydraulic fracture design can be evaluated. The primary method of evaluating stimulation performance is to analyze cumulative production received over a time period, and the rate at which the production return is realized. Variations in fracture design such as stage count, perforation cluster spacing, sand and fluid quantities, pump rates, etc., affect the grid blocks within the simulated reservoir differently (Figure 18), resulting in different production type curves. The resulting production will then be evaluated against the capital cost required to complete the stimulation. Once the economics and production are considered, an optimized stimulation design can be implemented in the field.

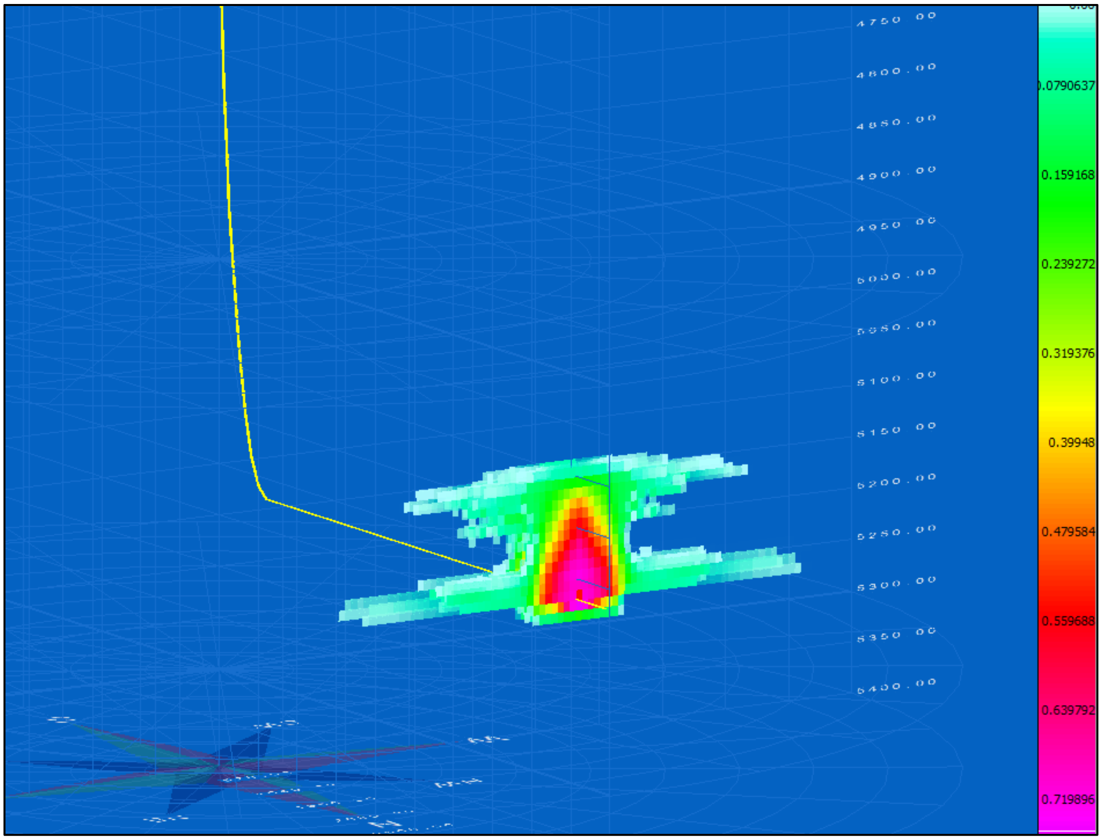

Figure 18: Northwest-Southeast cross section of Well J's simulated fracture showing the pounds per square foot of proppant concentration for a single stage with 5 perforation clusters

4.2 Comparison of Design Outputs

4.2.1 Production History Matching

In order to ensure the accuracy of the fracture to production model, field case wells were simulated and compared to the production witnessed within the field. In order to calibrate, four wells that targeted the northern ROZ play and that were within 15 miles of the proposed horizontal wells were selected. First the pump schedule for Well A, Well B, Well C, and Well D were simulated within GOHFER. Perforation spacing, fluid type, sand type, and pump rates were identical to what was ran for these wells. These pump schedules can be referenced in the appendix. As the jobs were simulated, the breakdown pressures and treating pressures during the job were very similar to what was seen in the field. A variance of 250 PSI pump pressure between the field and simulator was the maximum allowed to ensure the reality of the simulated jobs. Once the simulated stimulation mirrored field results, the production model was generated. When creating the production model, the most important aspect of the process was remaining consistent between the four wells. Alterations to the production model were made to get a best fit match between the GOHFER production model and field production between the four wells. The primary alterations included permeability to adjust the overall production, the acreage spacing for getting a decline curve that matched the field, and finding the constant water ratio that matched the field average. Since the wells were fractured differently and had different resulting production, the production model that was created had the best match between the four wells and was considered to best represent the field with the limited known data on the ROZ to date. Since the ROZ has had a limited production history, the four wells had an average lifetime production of 14 months. With this in mind, the best correlations were found for first year production. Two important factors in this match were cumulative production and year end rate. To simplify matters, oil production was used in quantifying the cumulative production and year end rates. Water and gas rates could be fit through ratio alterations that would not impact oil production as significantly as the earlier mentioned adjustments.

Table 8: GOHFER estimated production versus field results.

GOHFER Production	1 YR Oil Production (BBLS)	% of Actual production	1 YR End Rate (BPD)	% of Actual Rate
Well A	69,900	112%	115	100%
Well B	71,500	89%	128	98%
Well C	67,600	106%	117	97%
Well D	77,300	51%	161	54%

As seen in Table 8 the production matched relatively well with what was realized in the field with the exception of Well D. After further investigation, it was determined that FCD had a significant impact on the projected production indicated by the model.

Understanding which inputs the production model uses to create outputs allows the user to better understand how to boost production and ensure that what is being seen in the model matches field results. It was determined that Well D had a job nearly twice the size of the other wells, and having a job of this scale within the model dramatically increased the fractures half-length. With all the other variables staying relatively constant, this dramatically reduced the FCD. In the production model all the reservoir inputs are identical, so the main altering factor for production is the fracture conductivity.

Since Well A, Well B, and Well C had relatively similar volumes per stage, the results for their field and simulated production were relatively close. This was an important note during the sensitivity analysis section, because certain alterations that could impact the half-length or fracture width could in turn have a large implication on the resulting production.

Within the GOHFER software, the user can plot the actual field production against the simulated results, as seen in Figure 19 for Well C. This allows the user to evaluate the production simulated and ensure that the decline rates and cumulative production were similar to that of what was being seen within the field.

One of the first steps in justifying the model's production projections is to evaluate it against a field well that has been on production. Well A is located just over 8 miles southeast of the proposed Well J location, and is assumed to have very similar geologic characteristics. Well A has been on production for 17 months at the time of this study and the well's detailed stimulation design was made available for this study. In the GOHFER model a horizontal well stimulation was simulated using the exact same pump design that was used in the field. From there, a production model was generated and modified to match the production for Well A. This process was repeated with 3 other producing wells in the region and the same reservoir characteristics were used for all 4 models and a sound history match for production was achieved. Figure 20 displays the production rates for the first year of production and the modeled production in GOHFER for Well A.

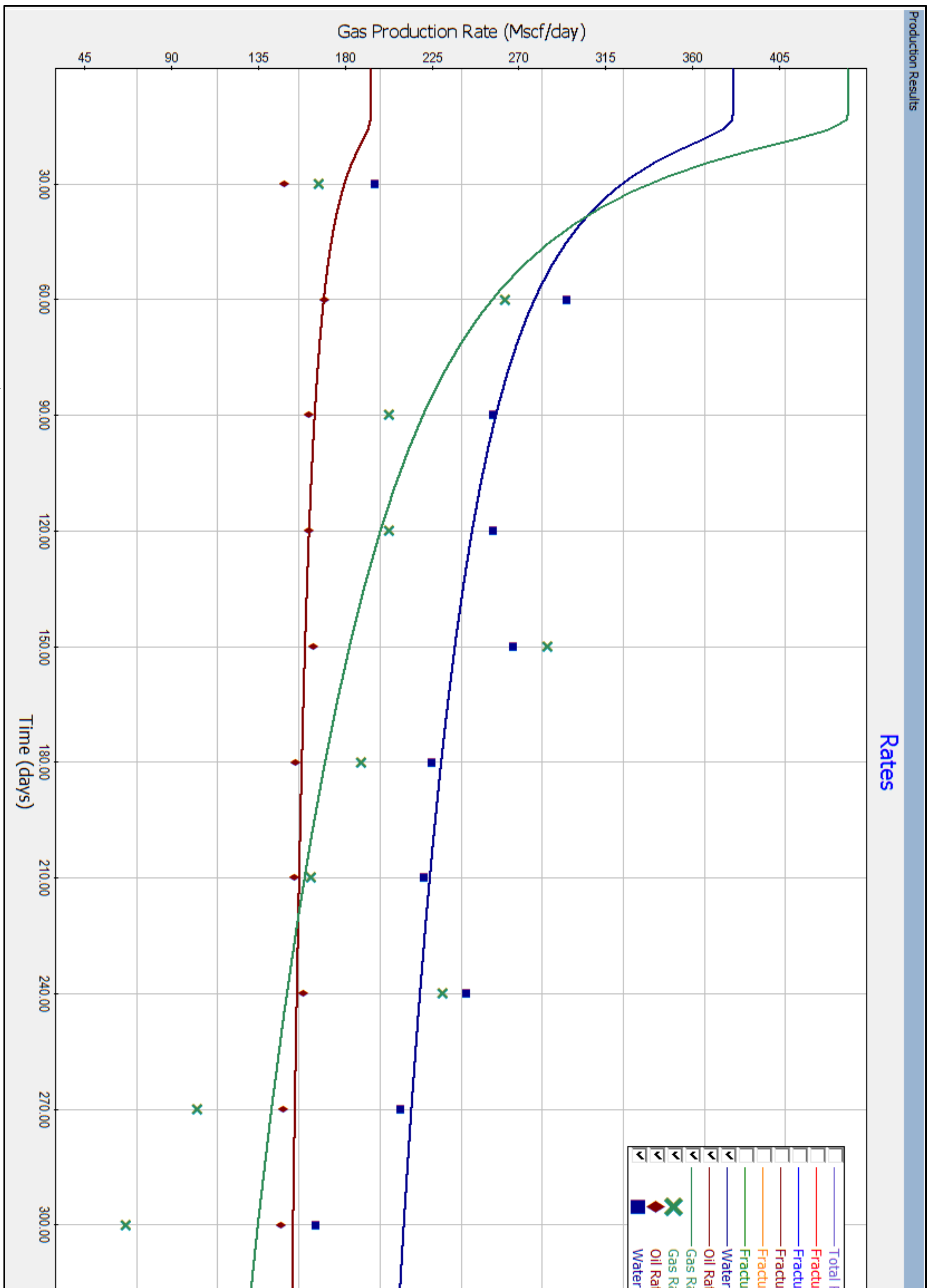

Figure 19: GOHFER simulated production overlaid with field data (Well C Actual vs Field Data)

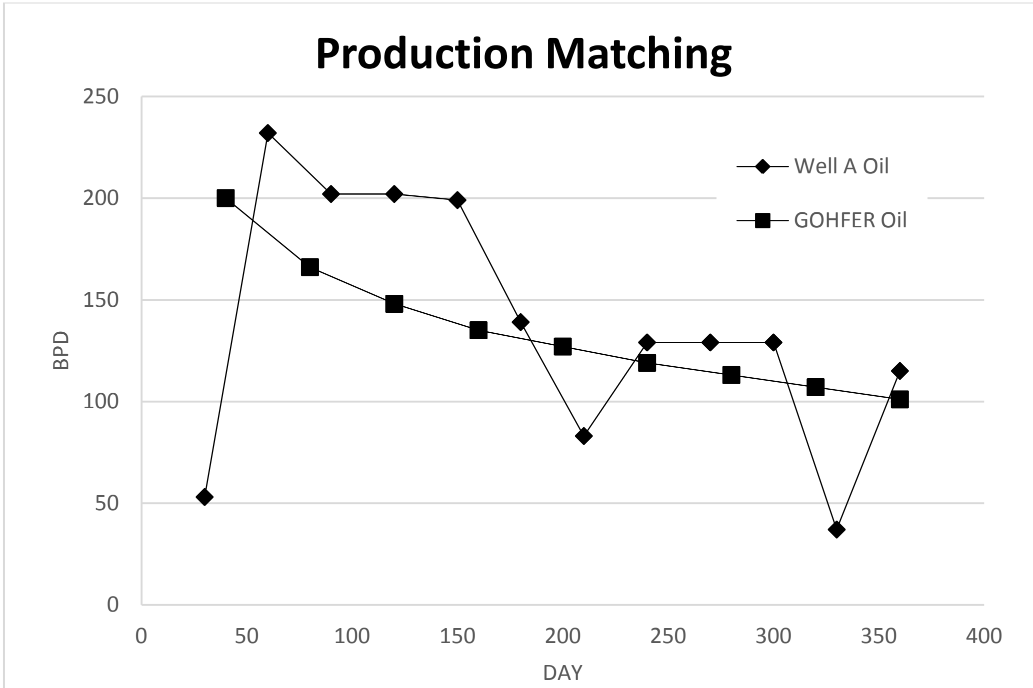

Figure 20: History production matching between field and GOHFER production estimates for Well A

The rates were very close in the history match but, more importantly, the first year oil production was also a close match. In the first year of production Well A produced 1649 barrels of oil, 1301 Mscf of gas, and 12,821 barrels of water. The GOHFER production estimate came to 1621 barrels of oil, 1293 Mscf of gas, and 14,587 barrels of water. With these results a confidence in the reservoir model and production mechanisms was achieved and stimulations designs alterations could commence and the value for each design could be determined.

4.2.2 Designs Considered

Twelve stimulation designs were initially considered. The pump schedule for all designs is listed in the appendix. Four of the twelve designs were field cases as previously mentioned, and were considered for Well J. Table 9 outlines the stimulation design for the twelve designs considered.

The detailed designs and pumping schedules are shown in the Appendix Table A1 through A-12. A brief outline of each design is as follows:

10 STG- The original design proposed. A 30/50 sand was selected to be pumped with a 12# linear gel to 12# crosslinked gel blend.

20 STG- The exact same design as the 10 STG, but the volumes for fluid and sand were halved and the amount of stages pumped was doubled.

20/40- The exact same design as the 10 STG, but the 30/50 sand was replaced with 20/40 sand.

Liberty- A hybrid job using slickwater to pump 70,000 lbs of 40/70 sand and crossing a 20# crosslinked gel to pump 125,000 pounds of 20/40 sand per stage.

Fat Finish- The exact same design as the 10 STG, but 16/30 sand was pumped at 3 pounds per gallon for the tailing sand stage.

Elite- A 13 stage design that used a 15# crosslinked gel to pump 150,000 pounds of 20/40 sand per stage.

More PPG- The exact same design as the 10 STG, but a 4 pound per gallon tail sand was pumped instead of a 3 pound per gallon.

Riley- Similar design to the Elite design, but less fluid volume pumped per stage.

Well A- Exact same stimulation design that was used in the field.

Well B- Exact same stimulation design that was used in the field.

Well C- Exact same stimulation design that was used in the field.

Well D- Exact same stimulation design that was used in the field.

Table 9: Initial stimulation designs considered in evaluation.

Design	**# of Proppant / STG**	**Fluid/STG (Gallons)**	**Stages**	**Cluster Spacing**	**Perfclusters / STG**	**1 YR OIL (BBLS)**	**3 YR OIL (BBLS)**	**AVG. FCD**
10 STG	150,000	137,260	10	60	5	58,100	105,900	5.83
20 STG	75,000	76,010	20	30	5	81,500	131,800	2.18
20/40	150,000	137,260	10	60	5	74,700	127,400	9.13
Liberty	195,800	186,775	10	60	5	82,000	136,300	11.6
Fat Finish	150,000	137,260	10	60	5	58,300	106,100	5.91
Elite	170,000	185,700	13	60	5	65,000	114,600	6.77
More PPG	200,000	149,760	10	60	5	46,900	94,500	2.34
Riley	170,000	178,400	10	60	5	63,800	110,800	7.76
Well B	155,400	203,670	10	75	5	71,500	126,300	6.22
Well C	127,150	159,020	10	65	5	67,600	126,700	6.03
Well D	306,000	274,205	12	60	5	77,300	166,000	2.81
Well A	160,786	187,950	10	60	5	69,900	126,200	6.5

Figure 21 displays the first year and third year cumulative oil production totals and compares each design accordingly. This demonstrates that some designs may have good initial production, but the longevity of the production will be short lived due to poor stimulated reservoir volume further from the wellbore.

After the analysis was conducted, there was a clear trend on the well's productive capabilities when dimensionless fracture conductivity was considered. The amount of sand volume pumped per stage did not have near the impact on production correlatively as FCD did. Figure 22 and 23 displays a comparison of sand volume pumped per stage and FCD with the resulting production.

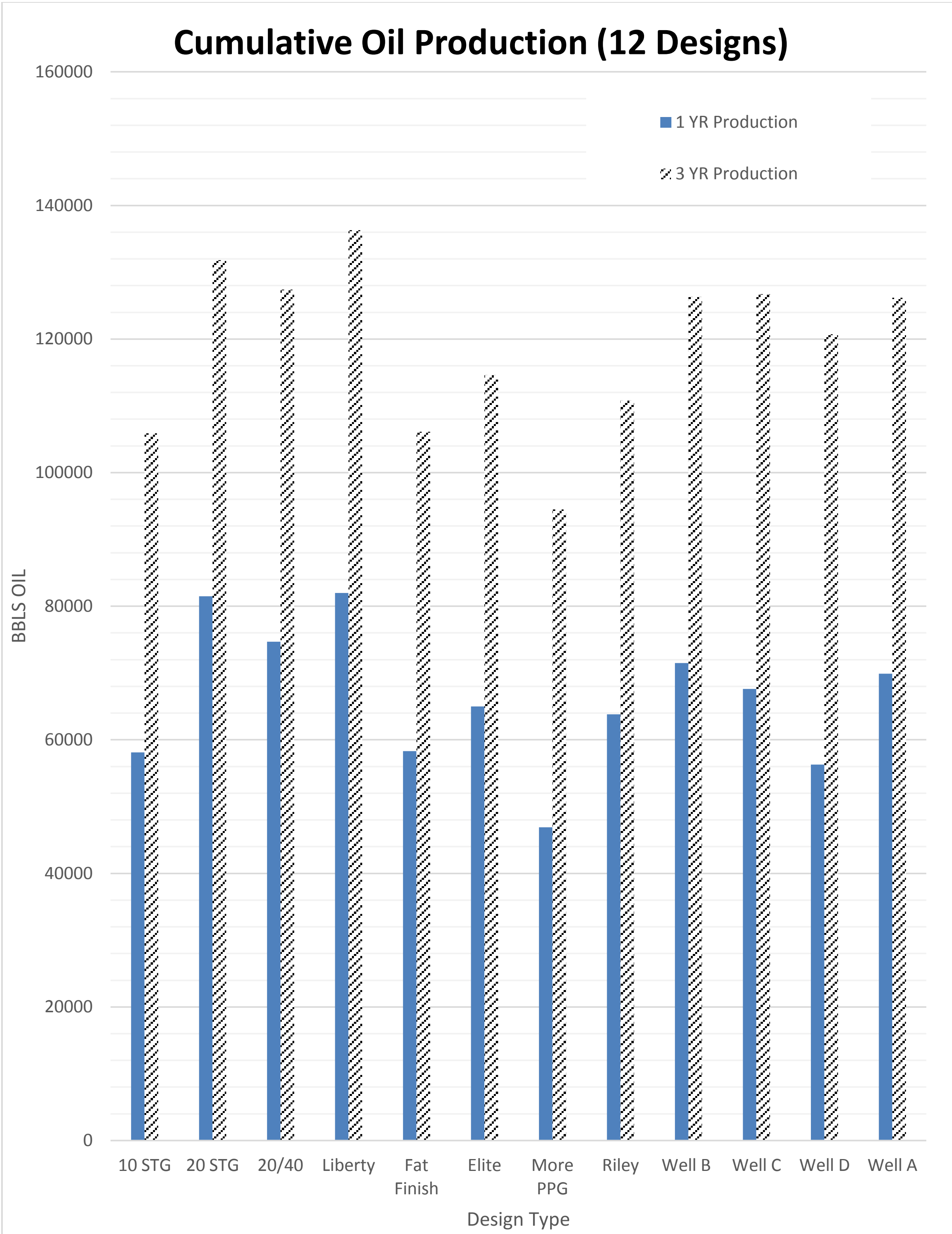

Figure 21: 1 and 3 year cumulative oil production for the 12 designs evaluated.

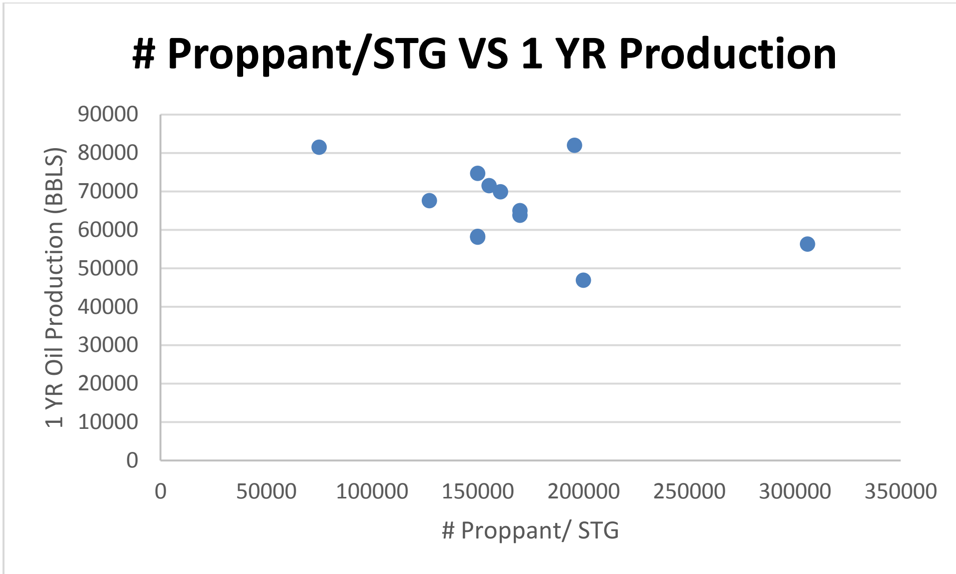

Figure 22: Simulated results of pounds of proppant versus first year production.

As seen in Figure 22, the 12 design simulations of varying stage volumes were run and no correlative effect was seen on the resulting production. As seen in Figure 23, the FCD for the exact same 12 well group had a strong correlation to the resulting production.

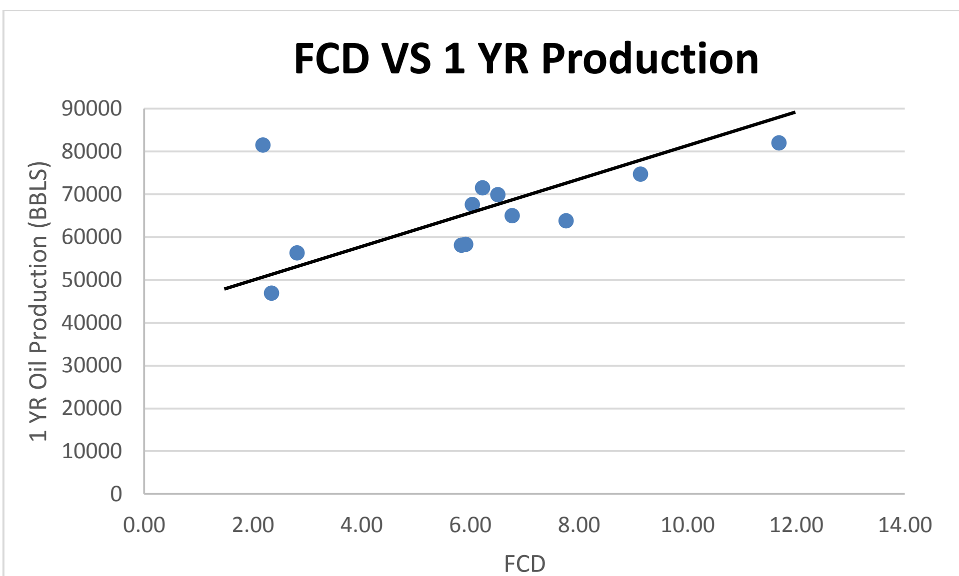

Figure 23: Simulated results of dimensionless fracture conductivity versus first year production.

FCD played a large role in the production output. When all other reservoir parameters are set the exact same, the conductivity within the fracture is what primarily gives one design an advantage over the others. This allowed the study to determine which design created the best base case scenario, and from there a sensitivity analysis was conducted on various design to optimize the production from the pool of better performing wells.

Lastly, for each design the capital expenditure can vary with the total job volume and pumping requirements. GOHFER includes an economic tool that considers original well cost, stimulation costs, and production, and outputs an estimated net present value for each design. Table 10 lists the economic inputs used for each design.

Table 10: Fixed Economic Conditions in GOHFER used for economic evaluation.

Economic Conditions	
Original Well Cost	$1,400,000
Monthly Well Costs	$7,500
Discounted Cash Flow	10%
Gas Price ($/Mscf)	$3.00
Oil Price ($/STB)	$45.00
Fluid Unit Cost (per Gallon)	$0.10
Fixed Job Cost (Pumping/Equipment)	$350,000
Proppant Unit Cost (per Pound)	$0.15

Knowing capital inputs, a net present value was calculated for each well's stimulation design. These values are high level, but give general insight into the well's economic capabilities. Table 11 lists each stimulation design and its net present value based upon the first year of production revenues.

Table 11: Stimulation design and net present value after first year of production

Simulation Design	
Stimulation Design	Net Present value
10 STG	$413,000
20 STG	$1,468,000
20/40	$1,159,000
Liberty	$1,371,000
Fat Finish	$1,760,000
Elite	$513,000
More PPG	($180,000)
Riley	$599,000
Well A	$873,000
Well B	$932,000
Well C	$1,628,000
Well D	$1,828,000

From the economical results seen in Table 11, the following takeaways can be seen. First, by adding more treatment stages, a greater amount of near wellbore stimulated rock volume was achieved and the resulting production justified the increased capital expenditure. Next, larger volume stages also increased the production within the first year and justified the additional capital expenditure needed. There were some cases where larger sized sand proved to have good economic results, but concerns over the fracture width being able to allow the sand to be pumped eliminated these designs from further evaluation.

After base economics were considered, a sensitivity analysis on each design was conducted to optimize each design. The following section covers this analysis.

4.2.3 Sensitivity Analysis

Upon completion of the 12 base case stimulation designs, various sensitivity analysis were conducted on a few best performing designs. This allowed for a fine tuning of the stimulation design and a determination of which parameters had the largest effect on production.

Too many fracture stages brings a high cost with diminishing returns. Therefore, the number of stages used in a horizontal well must be carefully considered. In order to determine an efficient stage count, the Liberty design was used to optimize the number of stages. To perform the analysis, the Liberty pump design was evaluated from 10 to 26 stages. The stage volumes were held constant throughout the analysis for comparison purposes. For each design the perforation cluster design was the exact same, but as stage count increased, the spacing between each perforation cluster was decreased to accommodate for the additional stages. Figure 24 displays the first year oil production relative to the amount of stages pumped.

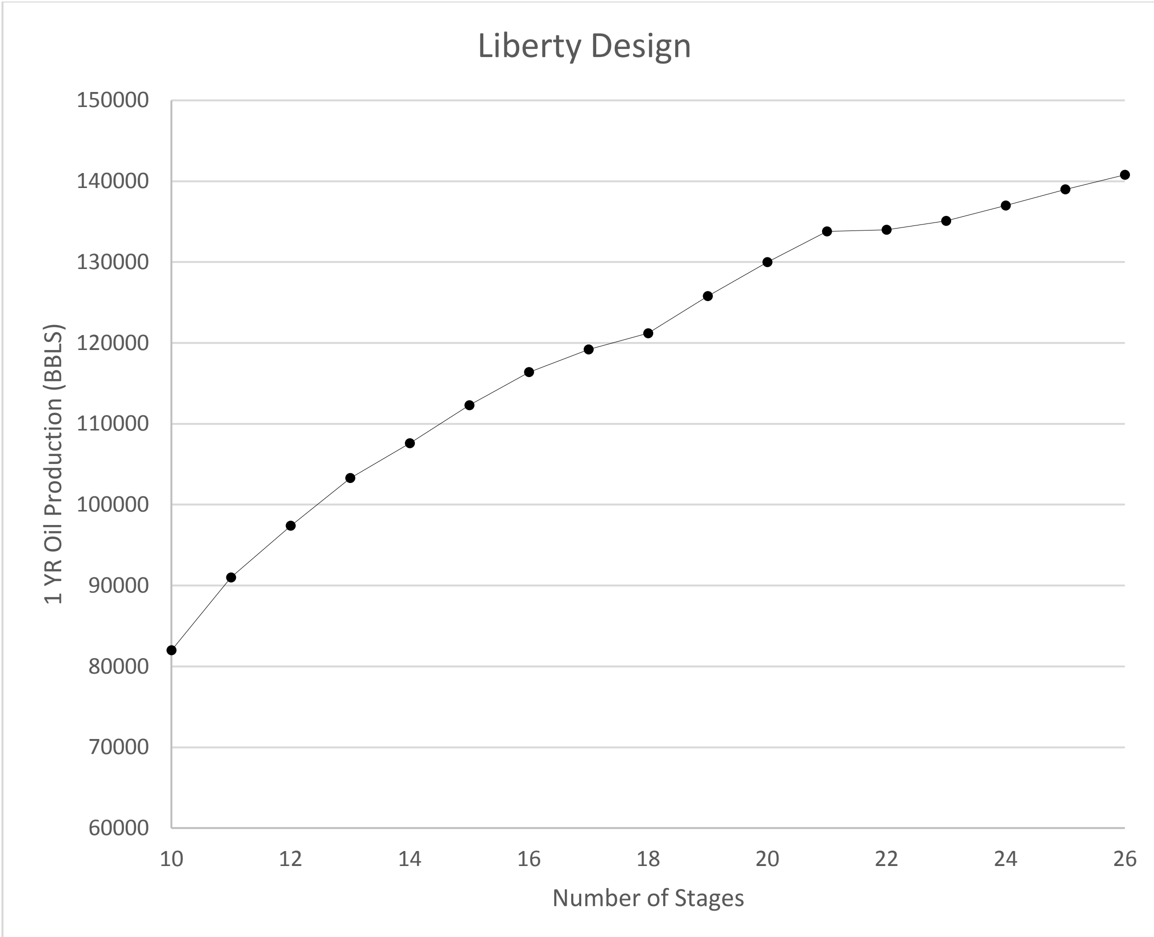

Figure 24: Number of stages pumped and resulting first year oil production.

After the analysis, it was determined that after 22 stages the resulting first year oil produced became detrimental to the economics of performing additional stages. With this in mind, a 20 stage count limit was set and determined to be the optimum stage count value.

Sand selection is a vital component of fracture conductivity. GOHFER software incorporates years of sand conductivity research within its evaluation process. To determine optimum sand selection, various 30/50 and 20/40 sized sand selections were evaluated on a closure stress versus measured conductivity basis, as seen in Figure 25.

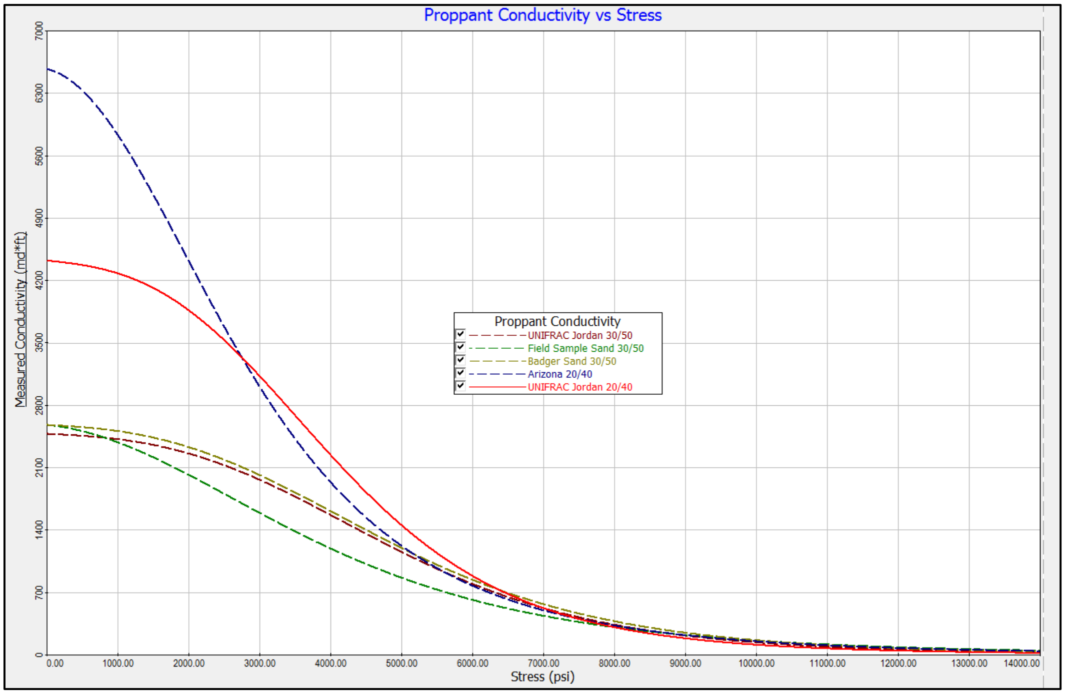

Figure 25: Sand conductivity versus closure stress

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After evaluation, at a true vertical depth near 5000 feet, a closure stress of 2200 PSI was estimated. According to conductivity measurements at that depth, the 20/40 sand had a slight advantage over the 30/50 sand selection. After a field evaluation, it was found that 30/50 sand had been the optimum sand selection in the region. In order to ensure that the sand could be pumped into the reservoir without any issues, and the fact that the 20/40 sand conductivity was not significantly greater than the 30/50 sand, 30/50 sand was selected as the sand of choice.

Determining optimum sand concentration is another critical parameter for stimulation design optimization. For this analysis, Well C’s tail sand concentration was altered in ½ pound per gallon increments, and the resulting production for first year oil production was analyzed, as seen in Figure 26.

After analysis, it was clear that higher sand concentrations during stimulation resulted in superior production. After a field analysis, it was found that no operator in the region had pumped above a 3 pound per gallon sand concentration. Once again, in order to ensure that the sand could successfully be pumped into the reservoir, a 3 pound per gallon sand concentration limit was set. As wells are developed in the area and stimulation pressure data is retrieved, it is apparent that this is an area that could prove to have substantial production benefits associated with it.

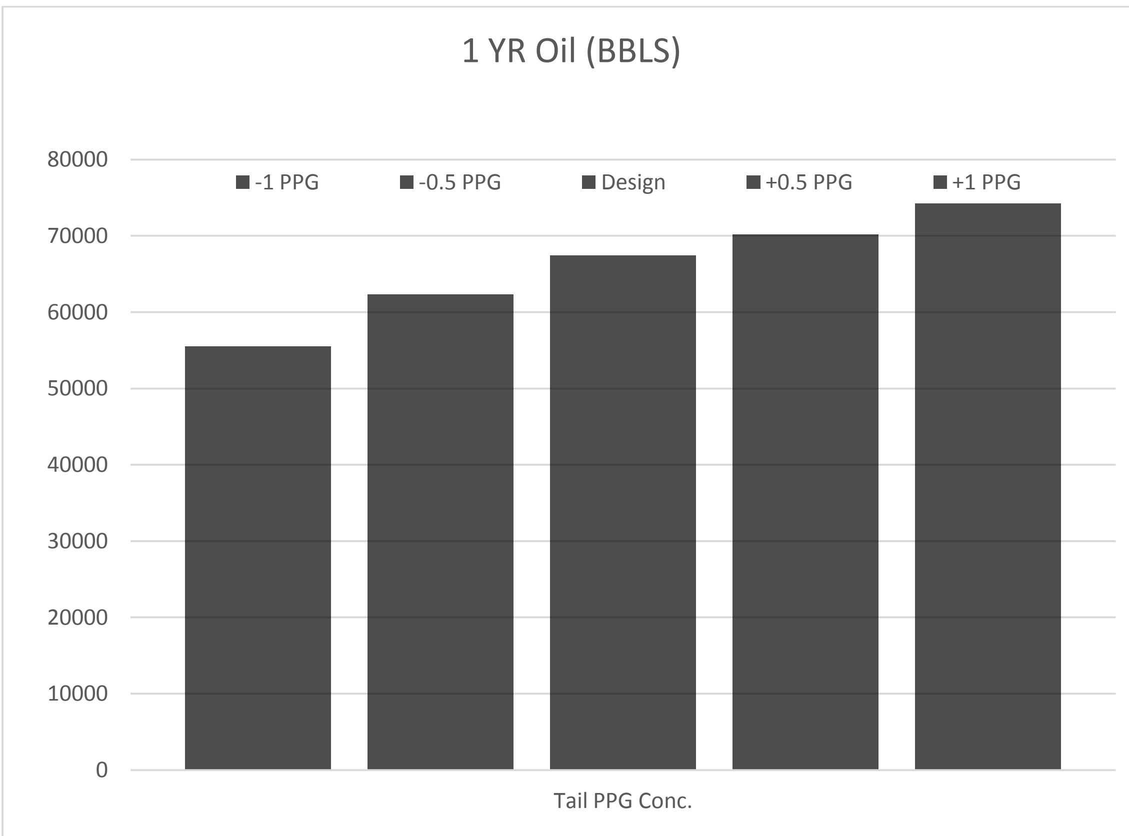

Figure 26: Tail sand concentration and resulting first year production.

Fluid selection plays a pivotal role in stimulation optimization as well. Slickwater (water with friction reducer added) is significantly less expensive than gelled borate fluids. Various attempts at pure slickwater designed jobs were modeled, but it was apparent that slickwater could not provide the fracture width needed to pump the higher sand concentration stages and would result in a screen-out during operations.

In order to keep stimulation costs as low as possible, a 12 pound per gallon (ppg) linear gel was determined to be the fluid of choice. This gel has the capability of becoming crosslinked during the higher sand concentration stages of the fracture to ensure the sand can be displaced into the reservoir. This fluid schedule is comparable to the fluids used successfully in other nearby stimulation designs, and was the best choice for the initial well. As additional stimulation pressure data is collected, the fluid selection can be optimized.

Rates at which fluid is pumped can have an impact on the production that is achieved. One important factor is achieving a rate high enough to keep the fracture open during stimulation, allowing sand to flow through the fracture. However, the issue with higher rates is that they require more horsepower and result in an increase to stimulation costs. For this study, a variety of pump rates were evaluated against Well C's pump design, and the first year oil production was evaluated, as seen in Figure 27.

After analysis, it was determined for this area that pump rate did not have a large impact on the resulting production. After a field analysis, it was found that a variety of pump rates ranging from 55 to 70 Barrels per Minute (BPM) were successful in displacing all sand into the reservoir. From this, a 55 BPM rate was determined as optimum because it could displace all sand and would require the least amount of horsepower to pump, resulting in more favorable economics for the operator.

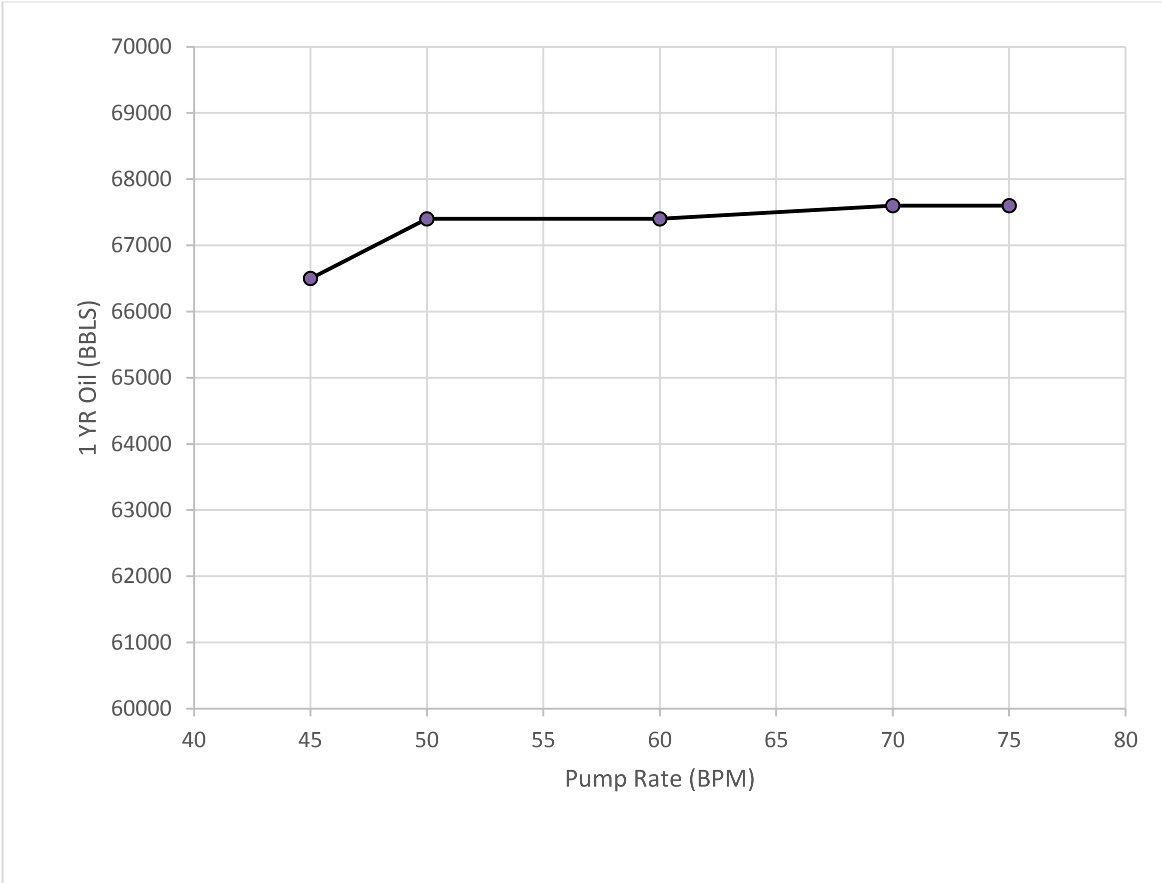

Figure 27: Stimulation pump rate versus first year oil production.

4.2.4 Findings

At the conclusion of the sensitivity analysis, some key points were found that could be used for the final fracture design for Well J. First, a 20 stage design that would incorporate a 55 foot cluster spacing design showed to be the optimum spacing design for wells in the region (Figure 24). A 30/50 sand had comparable conductivity versus a 20/40 sand (Figure 25), with the assurance that it can be pumped to design. A pure slickwater design risks screen-out, so a light borate design proves to be best. Lastly, a pump rate at which the sand can be displaced in the reservoir is sufficient; any rate exceeding that requires more horsepower cost and does not reflect in enhanced production (Figure 27). These parameters where key in the Well J stimulation design, which will be covered in the next section.

CHAPTER V

Fracture Design Optimization

This field case study targets horizontal wells drilled in the Sand Andres ROZ formation. A stimulation and completion guide were put together that focused directly on the area that was soon to be developed by the local operator. The following section gives a detailed description of advised treatment methods and the projected economic impact, and compares these methods to what has been already tried in the field.

5.1 Well J

Well J will have been stimulated by the time this study is published. Due to the timing of the project's completion, post stimulation performance cannot be evaluated. However, anticipated results will be covered and compared against producing wells in the area.

The final stimulation design was not selected based purely on economics. It also ensures that the design could be pumped without issue. The design incorporates a modeling technique accompanied by a common sense approach. As the field is developed and more data is collected, the design can be optimized and further evaluated.

5.1.1 Design Used

The design selected was a hybrid between a slickwater and crosslink stimulation treatment. The design shows good dimensionless fracture conductivity results in GOHFER, and similar treatment designs have had successful results in bordering acreage. The design maxes out at 3 pounds per gallon of proppant. Although greater proppant concentration has shown better results in the GOHFER software (Figure 26), it was recommended to only test at 3 pounds per gallon to see how the formation reacts before trying higher concentrations. The pump rate selected was 55 barrels per minute, as covered in the sensitivity analysis. The pump rate did not have a dramatic effect on production in this formation, so by reducing the pump rate, a lower horsepower requirement was needed and the stimulation cost was reduced. For the fluid selection, a 12 pound linear gel could be used for the initial sand stages, and the gel was crosslinked once the sand concentration was increased to over 2 pounds per gallon. This creates greater fraction within the fracture and increases the fracture width to ensure the higher proppant concentrations could be pumped into the formation. For the final stages of each stage, a 50 barrel overflush was recommended. The overflush will push the sand deeper into the formation and prevent the need for resin coated sand for the final stage, preventing sand migration during production. Table 12 displays the pump schedule recommended for each stage for the Well J prospect. Since the well is in a dolomite formation, the 15% hydrochloric acid that is used at the beginning of each stage will dissolve the dolomite near the wellbore and allow hydrocarbons to move to the wellbore without proppant near the perforations.

Pump Schedule							
Stage	**Step**	**Fluid**	**Gallons**	**Sand**	**Sand Conc.**	**Sand/STG**	**BPM**
1	Load Hole	Slickwater	2000	N/A	N/A	N/A	15
2	Acid	15% HCL	2000	N/A	N/A	N/A	15
3	Pad	Slickwater	15000	N/A	N/A	N/A	55
4	PLF 100 Mesh	Slickwater	10000	100 Mesh	0.5	5000	55
5	Sweep	12# Linear	20000	N/A	N/A	N/A	55
6	PLF 30/50	12# Linear	20000	30/50 White	1	20000	55
7	PLF 30/50	12# Linear	17500	30/50 White	1.5	26250	55
8	PLF 30/50	12# Linear	15000	30/50 White	2	30000	55
9	PLF 30/50	12# X-Link	12500	30/50 White	2.5	31250	55
10	PLF 30/50	12# X-Link	12500	30/50 White	3	37500	55
11	Spacer	12# X-Link	1260	N/A	N/A	N/A	55
12	Flush	Slickwater	10000	N/A	N/A	N/A	55
Total			***137760***			***150000***	

Table 12: Pump schedule for Well J

5.1.2 Stages and Perforations

Throughout the modeling process it was determined that smaller stage volume and more stages resulted in better production. By increasing the stimulated reservoir volume near the wellbore, better production could be achieved. As more stages are added to the stimulation design, the cluster spacing between the perforations is decreased and more of the reservoir rock near the wellbore is stimulated. As seen in Figure 24, once there are over 20 stages pumped, the resulting production becomes a diminishing return. Keep in mind that each simulated stage requires four perforation clusters per stage. As a result, a 20 stage stimulation plan was selected for Well J, with 55 feet between each set of perforation clusters. After 20 stages are completed, the total treated length on the wellbore will be 4345 feet. This fits within the permitted bounds of hydraulic fracturing in New Mexico.

After the proposed design was input into GOHFER software, the projected proppant cutoff length was estimated to be no greater than 350 feet. This assured that with the selected design, wellbore within the section would not be impacted by the hydraulic fracture. With this in mind the environmental concern for this operation was eliminated, but the operator was advised to monitor well bore pressure for all wells in the section during stimulation as a good operating practice.

5.1.3 Scale Prevention

As described in previous sections, the San Andres ROZ is plagued with anhydrite throughout the formation. Anhydrite creates a calcium sulfate ($CaSO_4$) scale that can reduce production and damage downhole and surface equipment. In order to reduce the effects of scale on production, two design plans were incorporated into the design. The first was the use of increased concentrations of liquid scale inhibitor. In general, stimulation case scale inhibitor is typically added to the fracturing fluid at concentrations of .25 to 1 gallons per thousand gallons of treatment fluid. For Well J, a 2 gallon per thousand addition of scale inhibitor concentration will be used. An issue with liquid scale inhibitor is that during the flowback period, liquid scale inhibitor flows out with produced hydrocarbons, decreasing the overall inhibitor concentration and allowing scale production to immediately occur. In order to prevent long term scaling issues, a coated proppant was used. CARBO SCALEGUARD is a porous ceramic proppant that has a controlled release of scale inhibiting chemicals. The ceramic proppant will be mixed with the sand during stimulation at a 1.5% concentration to total sand volume. Figure 28 displays the integrity of the ceramic proppant compared to a standard ceramic proppant. The chosen proppant mix insures that the propped fracture will not collapse and ceramic fines will not be produced.

In addition to the ceramics integrity, the most important property it has is the slow release of scale inhibiting chemicals. It has been determined that a 2.5 parts per million scale inhibitor concentration can effectively reduce the effects of scale on a producing well. In a field case study, CARBO measured the amount of scale inhibiting chemicals released during production. As seen in Figure 29, after 500 days of production, SCALEGUARD was able to release nearly double the amount of scale inhibiting chemicals needed to effectively mitigate scale within the wellbore.

As expected, ceramic proppants are not nearly as cost friendly as plain sand. Since the SCALEGUARD is only required at 1.5% concentration, it makes the economics workable. Well J will be one of the first wells in the area to experiment with the use of SCALEGUARD, but wells that did not use the ceramic proppant would need a remediation workover within the first 24 months of production that could cost as low as $250,000 to complete. The economics behind using SCALEGUARD versus a workover procedure make the use of ceramic proppant considerably more favorable.

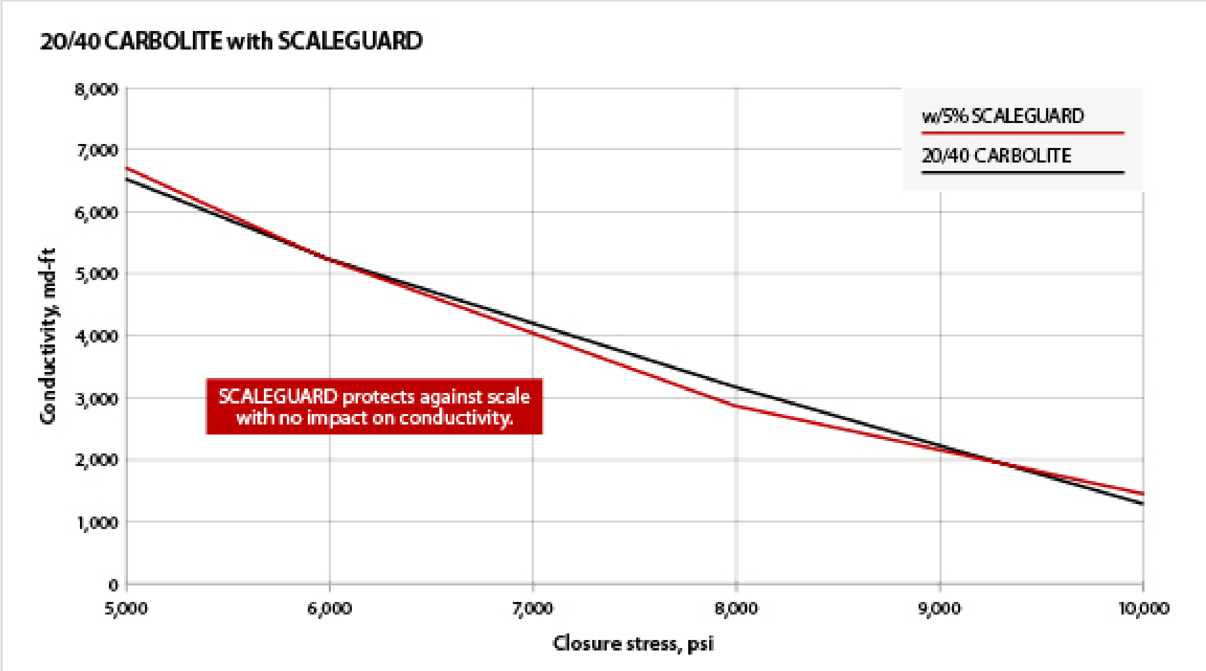

Figure 28: CARBO SCALEGUARD conductivity versus closure stress.

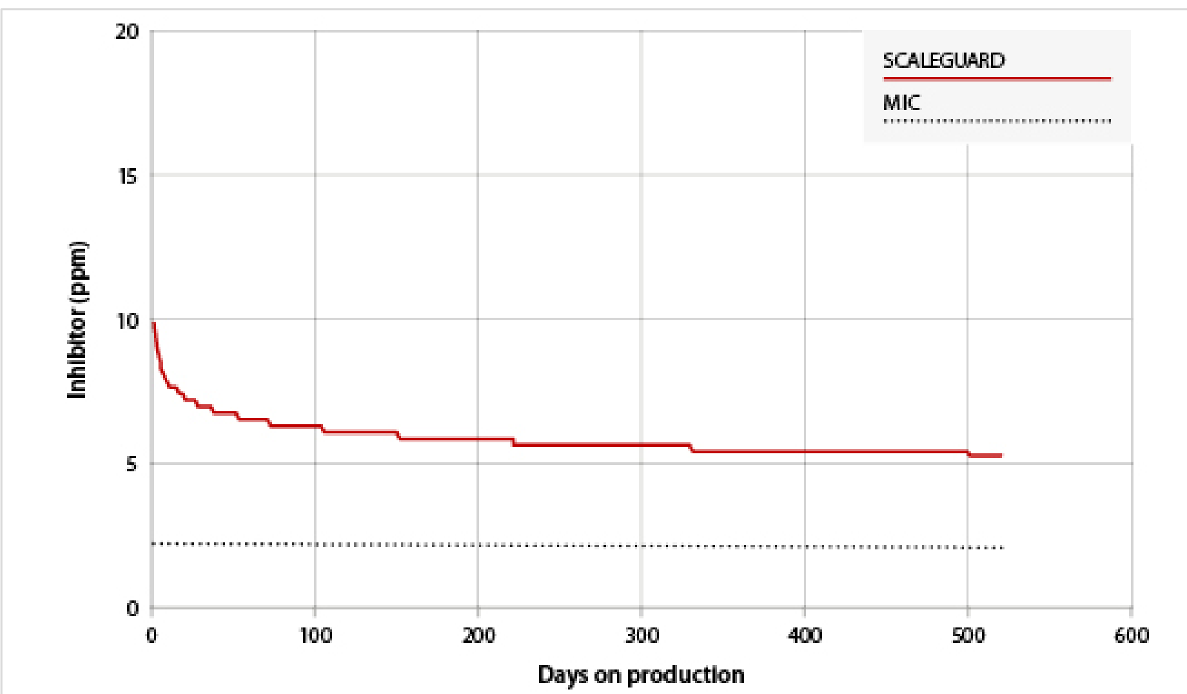

Figure 29: SCALEGUARD chemical release concentration versus days on production.

5.1.4 Remediation Treatment

Many operators have already found solutions to scaling that have had success and should be implemented. On a three well case study, a nearby operator determined that scale was limiting production. They used a workover remediation procedure that is as follows:

1. Evaluate the Electric Submersible Pump (ESP) for scale deposition, usually in the gas separator and pumps
2. Run a drill bit to mechanically clean out scale from the entire horizontal section of the wellbore, typically without the return of drilling fluids.
3. Pump a scale converter mixed with water across each set of perforations and let soak for 24 hours. This process converts $CaSO_4$ to an acid dispersible byproduct.
4. Acidize each set of perforations with 10,500 gallons of 15% NEFE HCl and let soak for six to 12 hours.
5. Spot scale inhibitor (polyacrylate/deta phosphonate blend) across each set of perforations and let soak for 48 hours.
6. Install the ESP and put back on production.

The entire workover procedure costs approximately $250,000. The benefit of the remediation treatment was clearly witnessed, with two of the three wells coming back on to production with rates higher than their initial production rates. These increased production rates would pay out the remediation treatment in less than one month before taxes, expenses, and royalties were considered. Figure 30 demonstrates the results of the remediation on the three case wells studied.

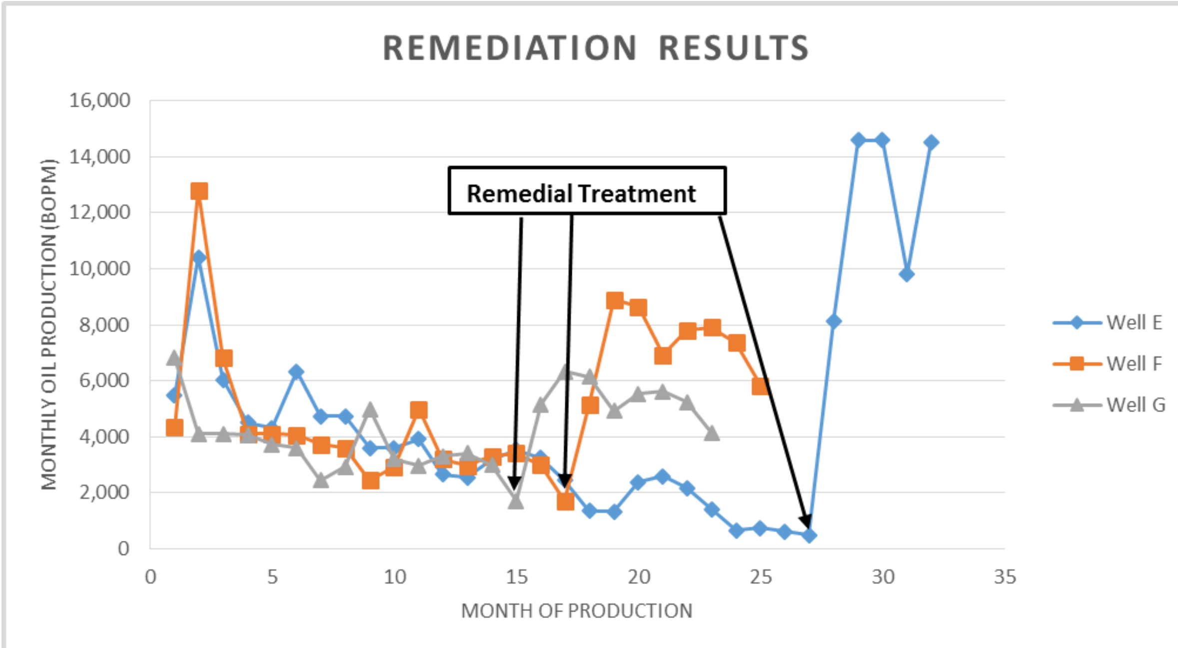

Figure 30: Resulting production rates post scale remediation treatment.

5.1.5 Economics

For the stimulation design selected for Well J, a more comprehensive economic evaluation was conducted using Petroleum Fiscal Analysis Program (PFAP) software (Hareland 2017). PFAP is an in-house tool created by the Oklahoma State Petroleum Engineering department. PFAP software calculates the capital costs and production forecasts and gives an economic evaluation of a project. The CAPEX calculator accounts for drilling, completion, and production costs. The production flow model sheet estimates forecasts based on decline exponent, decline rate, initial production rate, and gas-to-oil ratio. The economic evaluation section accounts for CAPEX, taxes, royalties, OPEX, and discounted cash flow rates. From all the inputs combined between the three function pages, output data is displayed. The output data includes net present value, IRR, payback period, and return on investment. A sensitivity analysis can be conducted in the sheet that measures the impact on expenses, production, and oil price to measure the project’s profitability through various risk analysis scenarios. Figure 31 displays the input and output data column for the economic evaluation section of the PFAP software.

Input data		
CAPEX	$ 2,475,000.00	
CAPEX Sensitivity	100%	
OPEX Sensitivity	100%	
Oil Price Sensitivity	100%	
Gas Price Sensitivity	100%	
Projected Online	Jan 1 2018	
Working Interest	100%	
Royalties	20.00%	
State Tax	5.5%	
Discount Rate	10%	
Depletion	7	Years
MACRS	7	Years
Intangible Assets	$ 2,000,000.00	USD
Tanigible Assets	$ 1,000,000.00	USD
SWD	0.15	$/BBL
WOR	4.5	BBL/BBL
Reinvestment rate	8%	
Labor	10000	$/Year
Labor Annual Inc	3%	/Year
Utilities	60000	$/Year
Utilities Annual Increase	2%	/Year
Workover	20000	$/Year
Workover Annual INC	3%	/Year
Fed tax rate	35%	

Output Data	AFIT	
NPV	$4,837,827.14	USD
IRR	76.44%	
MIRR	12.51%	
Payback	0.93	Years
Discounted Payback	1.03	Years
Discounted ROI	215%	
Discounted Sum	$ 7,796,609.86	USD
NPV @ 8%	$5,524,646.89	USD
NPV @ 10%	$4,837,827.14	USD
NPV @ 13%	$4,017,706.58	USD
NPV @ 15%	$3,574,603.85	USD
NPV @ 20%	$2,715,679.19	USD
Total Oil	629761	BBLS
Total Gas	314880	MSCF

Figure 31: Input and output data from PFAP software.

Based on the production estimated for Well J, various oil price scenarios were ran. The resulting NPV and IRR are listed in Table 13.

Table 13: Oil Price Sensitivity for Well J.

Price Sensitivity					
WTI Oil Price	\$45.00	\$50.00	\$55.00	\$60.00	\$65.00
NPV	\$4,837,827	\$5,584,297	\$6,330,767	\$7,077,237	\$7,823,707
IRR	76%	86%	96%	107%	117%

Sensitivity to oil price compares a well against what other wells in the region are witnessing for their oil price sensitivity as covered in previous sections. In conjunction with oil price, a sensitivity analysis was conducted on CAPEX, OPEX, gas price, and disposal costs. Each parameter was individually analyzed one value at a time, and the base case values were held constant. The values were altered on a percentage basis, and the resulting IRR was measured. Figure 32 displays the effects of these parameters on the project's success.

It is clear that capital expenditure and oil price have the largest impact on the Well J's economics. Disposal costs are important, and if an operator cannot have their own disposing facility, disposal costs in the region can be as high as \$1.00 per barrel. This would result in an IRR of 67% for the well. Another important topic is production. The PFAP sheet is set for a 30 year time frame, whereas the San Andres ROZ development has only produced for nearly three years. So, long term production projects can be difficult to estimate. The positive side is that most oil wells generate most of their cash flow within the first five to ten years of production, and these values are much more reasonable to estimate and have the greatest impact on the well's economics.

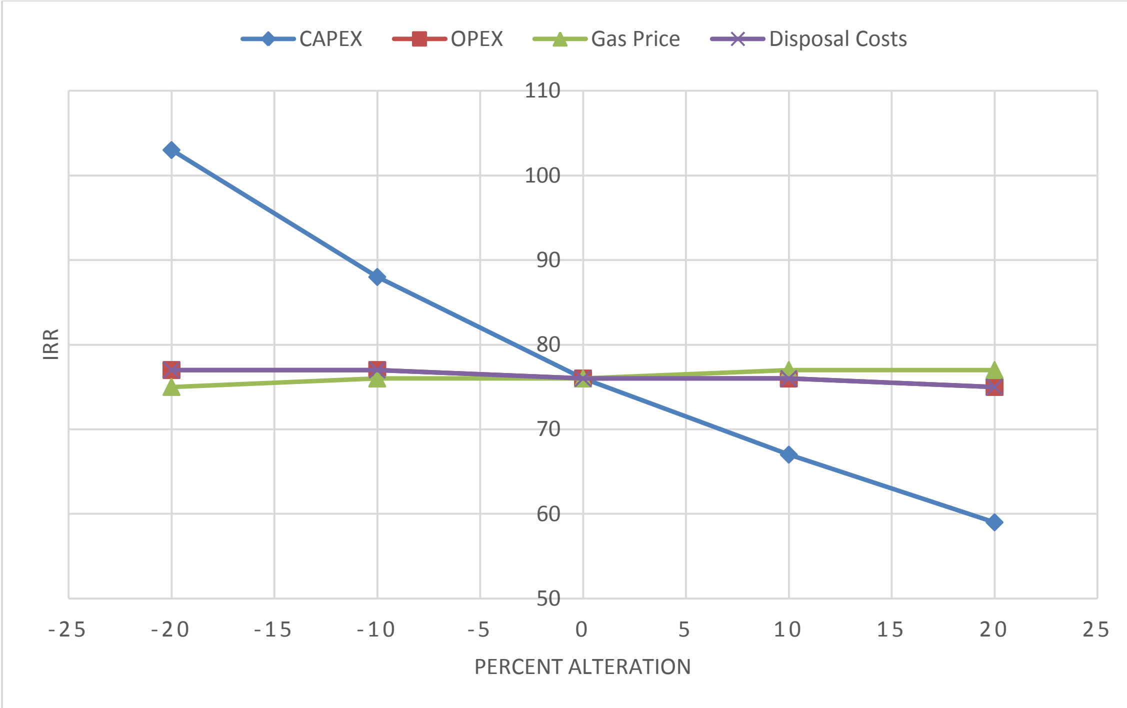

Figure 32: IRR Sensitivity analysis for CAPEX, OPEX, Gas Price, and Disposal Costs.

In summary, after a thorough risk analysis of Well J's economics, the results prove that this well is economically viable under a variety of economic conditions. To enhance economics, Well J will be the pilot well for a development project. As more wells are drilled, the expenses for the wells will decrease through operational learning and less costly infrastructure requirements. This will boost the economics for future wells to higher values and continue to raise the net asset value for the development.

CHAPTER VI

CONCLUSIONS AND DISCUSSIONS

This study compared net present value, internal rate of return, initial production, first year production, and estimated ultimate recovery on over 15 types of hydraulic fracture designs. All designs were tested in a reservoir matrix that would simulate the production capability of the Well J prospect. Considerations for the initial capital needed for each design and the resulting production cut the design pool down to the best value creating designs. Once the best designs were determined, field experience and tried-and-true practices from adjacent wells within the ROZ development determined the most logical stimulation design.

The results of the study determined that increased stage count and tighter perforation cluster spacing, compared to previous designs, would increase the capital cost of the well. However, the resulting production from the increase in simulated reservoir rock volume justified the increase in capital expense. Additional optimization measures were found throughout the study, and as the field is developed and best reservoir information is collected, these designs have the chance to further improve the recovery of the ROZ development.

In addition to the optimized stimulation design, this study also uncovered the best treatment practices of the play to boost long term earnings. These findings include the use a scale inhibiting proppant, increased use of liquid scale inhibitor during treatment, addition of chlorine dioxide during treatment, and use of a capillary string during production. These findings will result in a deferred time period of workover treatments on the well that can cost as little as $250,000. They also provide a means of a better cleanup of the fracture pack within the reservoir, allowing for increased reservoir productivity.

6.1 Project Value

Comparative values between the originally proposed pump design and the new design pumped gives insight to the value of this project. Figure 33 displays the project oil production for the first year with the original design and the design that has been recommended.

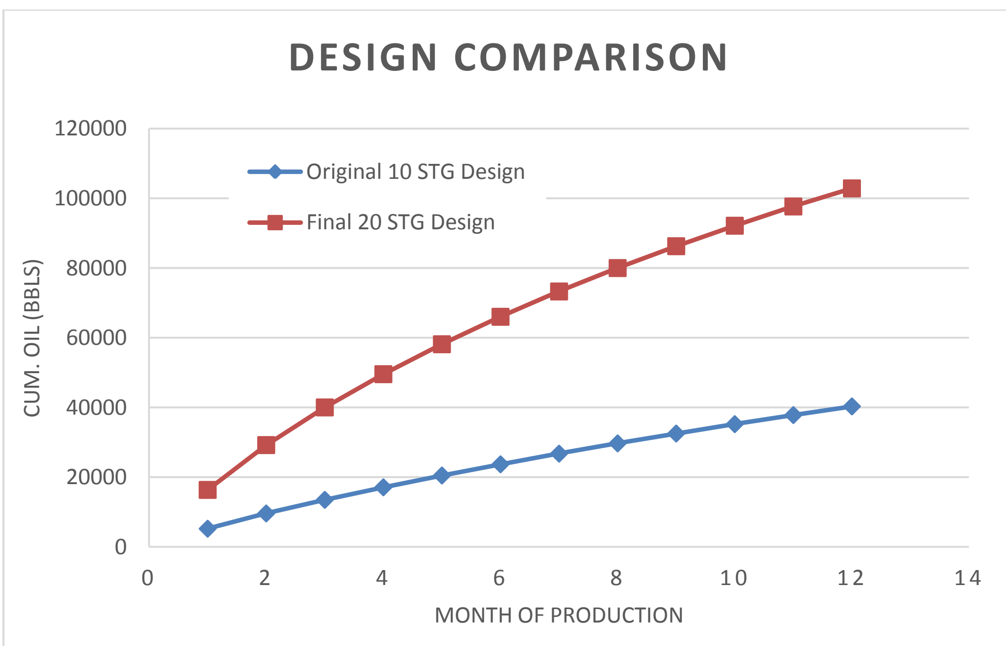

Figure 33: Cumulative first year oil production 10 stage proposal versus 20 stage proposal.

The initial projected value gained within the first year is an additional 62,550 BBLS of oil recovered. At $45.00 WTI oil price, this would reflect an additional $2,814,750 in first year earnings before taxes, royalties, and expenses.

Just the initial production increase for the well should not be the only consideration made when determining the project's added value. There are many intangible earnings associated with completing a more successful well. One large additional earning will be the value of the acreage near the well. If a well shows good production, results of the acreage nearby will increase in value and give the company owning that acreage a substantial boost in net worth. Another great perk for future development is that investors now have a proof of concept in the area. When investors lend money to the operator, it will be considered to have less risk associated with it, and the interest charged on future loans will decrease, giving the operator more earned value in subsequent wells.

6.2 Betterment of Input Data

As ROZ development progresses forward, vital information about the reservoir can be collected to enhance the knowledge about the play and determine more optimized stimulation practices for future wells.

One method of improving stimulation techniques is through the use of micro-seismic monitoring of the stimulation job. As seen in Figure 34, micro-seismic monitoring involves the use of a fiber optic tool string in an adjacent wellbore during the treatment of a well. The micro-seismic information is recorded and determines the size and direction of the fracture through downhole micro-seismic events. This information can be compared against a hydraulic fracturing simulation to ensure that the projected fracture lengths and heights correlate to what is actually occurring during treatment. Then the simulated model can be adjusted to ensure the model more accurately replicates reservoir conditions.

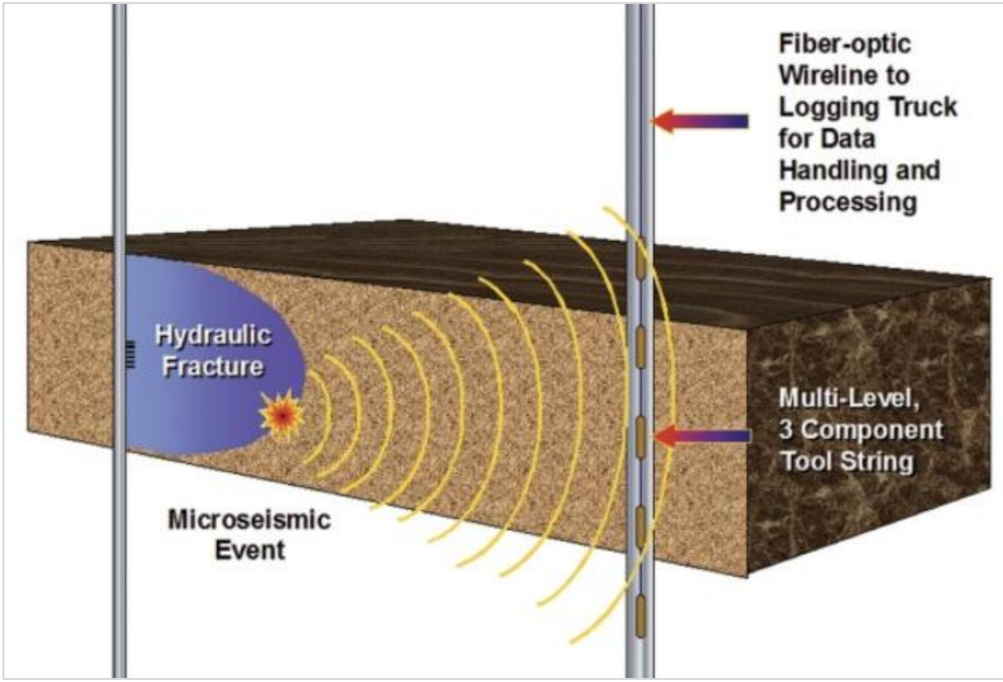

Figure 34: Micro-seismic monitoring during a hydraulic fracture operation (Clarkson, 2011)

A post treatment measurement during production utilizing a composite carbon rod ran into the well can give an insight on fracture efficiency. These carbon rod systems monitor flow from each individual set of perforations, and this data reflects the cluster efficiency during treatment. Improving cluster efficiency through the use of diverters during treatment allow for a more evenly dispersed fluid, and proppant within the reservoir and create more stimulated rock volume that will result in increased production.

Additional logging measurements and data collected while drilling are means of increasing knowledge about the reservoir. Although these measurements will result in an increase of capital expenditure, many of these tests can be ran just one time. The information gathered can be used on multiple wells in the section to increase the production and economics of subsequent wells that will explore the development area.

CHAPTER VII

FUTURE WORK

Optimized Perforations: Based off of previous studies (Mohammad, 2015 & Tahmeen, 2017), horizontal drill data can be used to predict rock properties that are key to optimizing hydraulic fracture design. During the drilling process, Downhole Weight on Bit (DWOB) can be calculated, and from DWOB in conjunction with inverted rate of penetration (ROP) models, Unconfined Rock Strength (UCS), Young's Modulus, porosity, permeability and Poisson ratio and can be determined. Throughout the horizontal well, the rock properties change, and with evenly spaced perforation clusters, the hydraulic fracture growth becomes uneven and results in non-productive clusters. The opportunity lies in an engineered placement of clusters for each stage that distributes the sand and fluid in a more effective manner. In a study by Kerkar (2014) in the Marcellus, three wells targeted the same formation, with the same treatment fluid and proppant. After treatment better production was realized on the wells that were selectively perforated. These same concepts can be applied to the ROZ play in the future to continue to improve operator's net asset value (NAV) during exploration and production.

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APPENDIX A

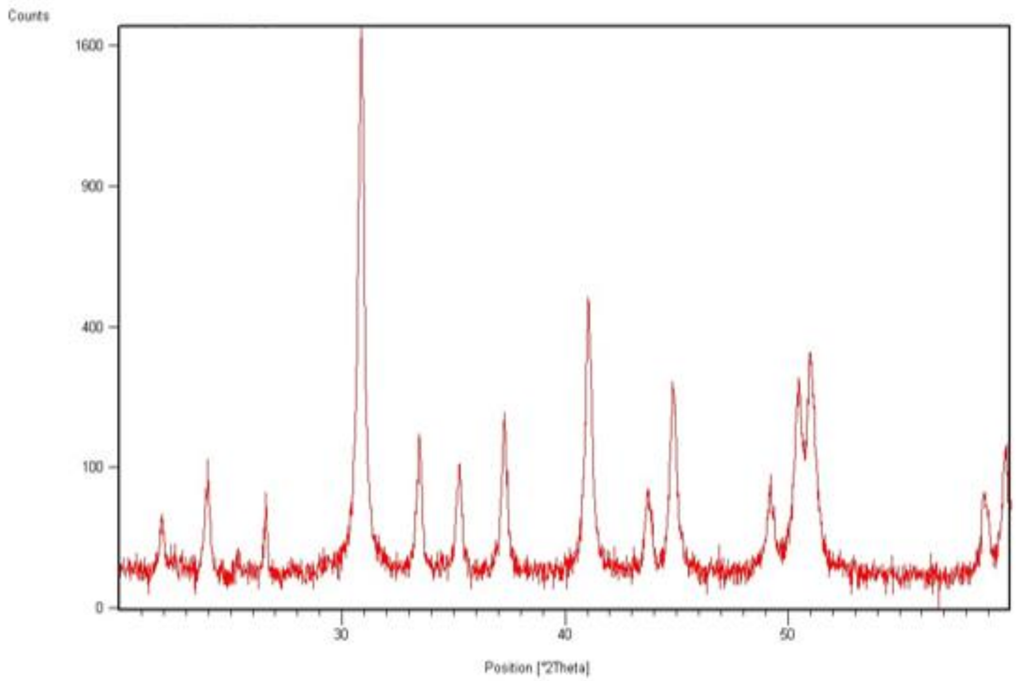

Figure A-1: XRD analysis from cored well

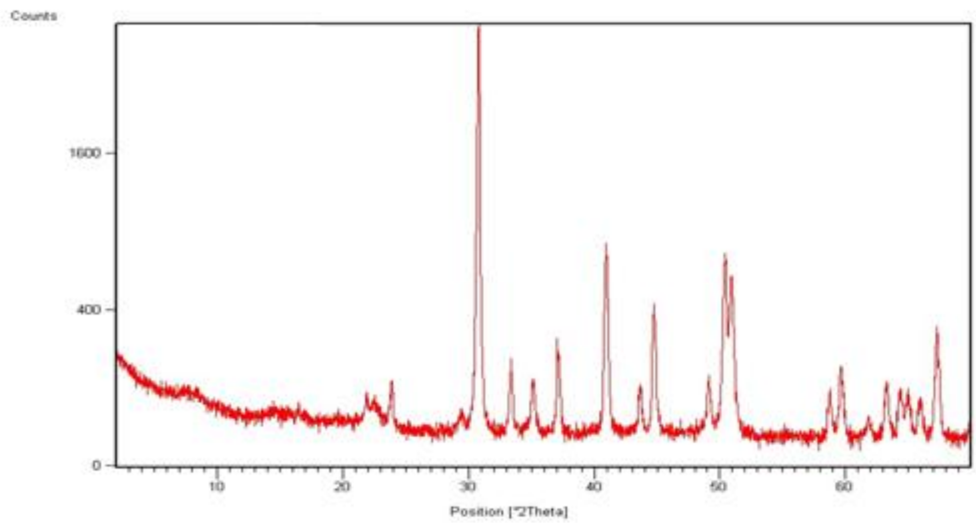

Figure A-2: XRD analysis from standard dolomite

STIMULATION PUMP SCHEDULES

Table A-1: Stimulation Pump Schedule for 10 STG Design

NAME: 10 STG STAGE COUNT: 10						
Stage	**Fluid**	**Volume (Gallons)**	**Proppant**	**Prop. Conc. (PPG)**	**Cum. Prop. (LBS)**	**Rate**
1	Slickwater	2000	-	0	0	20
2	15% HCl Acid	2000	-	0	0	70
3	Slickwater	15000	-	0	0	70
4	Slickwater	10000	UNIFRAC Jordan 100 Mesh	0.5	5000	70
5	Guar_15#	20000	-	0	5000	70
6	Guar_15#	20000	UNIFRAC Jordan 30/50	1	25000	70
7	Guar_15#	17500	UNIFRAC Jordan 30/50	1.5	51250	70
8	Guar_15#	15000	UNIFRAC Jordan 30/50	2	81250	70
9	Guar_15#	12500	UNIFRAC Jordan 30/50	2.5	112500	70
10	Guar_15#	12500	UNIFRAC Jordan 30/50	3	150000	70
11	Guar_15#	1260	-	0	150000	70
12	Slickwater	9500	-	0	150000	70

Table A-2: Stimulation Pump Schedule for 20 STG Design

NAME: 20 STG STAGE COUNT: 20						
Stage	**Fluid**	**Volume (Gallons)**	**Proppant**	**Prop. Conc. (PPG)**	**Cum. Prop. (LBS)**	**Rate**
1	Slickwater	2000	-	0	0	20
2	15% HCl Acid	2000	-	0	0	70
3	Slickwater	7500	-	0	0	70
4	Slickwater	5000	UNIFRAC Jordan 100 Mesh	0.5	2500	70
5	Guar_15#	10000	-	0	2500	70
6	Guar_15#	10000	UNIFRAC Jordan 30/50	1	12500	70
7	Guar_15#	8750	UNIFRAC Jordan 30/50	1.5	25625	70
8	Guar_15#	7500	UNIFRAC Jordan 30/50	2	40625	70
9	Guar_15#	6250	UNIFRAC Jordan 30/50	2.5	56250	70
10	Guar_15#	6250	UNIFRAC Jordan 30/50	3	75000	70
11	Guar_15#	1260	-	0	75000	70
12	Slickwater	9500	-	0	75000	70

Table A-3: Stimulation Pump Schedule for 20/40 Design

NAME: 20/40 STAGE COUNT: 10						
Stage	**Fluid**	**Volume (Gallons)**	**Proppant**	**Prop. Conc. (PPG)**	**Cum. Prop. (LBS)**	**Rate**
1	Slickwater	2000	-	0	0	20
2	15% HCl Acid	2000	-	0	0	70
3	Slickwater	15000	-	0	0	70
4	Slickwater	10000	UNIFRAC Jordan 100 Mesh	0.5	5000	70
5	Guar_15#	20000	-	0	5000	70
6	Guar_15#	20000	UNIFRAC Jordan 20/40	1	25000	70
7	Guar_15#	17500	UNIFRAC Jordan 20/40	1.5	51250	70
8	Guar_15#	15000	UNIFRAC Jordan 20/40	2	81250	70
9	Guar_15#	12500	UNIFRAC Jordan 20/40	2.5	112500	70
10	Guar_15#	12500	UNIFRAC Jordan 20/40	3	150000	70
11	Guar_15#	1260	-	0	150000	70
12	Slickwater	9500	-	0	150000	70

Table A-4: Stimulation Pump Schedule for Liberty Design

NAME: Liberty STAGE COUNT: 10						
Stage	**Fluid**	**Volume (Gallons)**	**Proppant**	**Prop. Conc. (PPG)**	**Cum. Prop. (LBS)**	**Rate**
1	Slickwater	1000	-	0	0	25
2	15% HCl Acid	3000	-	0	0	25
3	Slickwater	30000	-	0	0	60
4	Slickwater	10500	UNIFRAC Jordan 100 Mesh	0.2	2100	60
5	Slickwater	10500	UNIFRAC Jordan 100 Mesh	0.4	6300	60
6	Slickwater	10500	UNIFRAC Jordan 100 Mesh	0.6	12600	60
7	Slickwater	12000	Badger Sand 40/70	0.6	19800	60
8	Slickwater	12000	Badger Sand 40/70	0.8	29400	60
9	Slickwater	12000	Badger Sand 40/70	1	41400	60
10	Slickwater	12000	Badger Sand 40/70	1.15	55200	60
11	Slickwater	12000	Badger Sand 40/70	1.3	70800	60
12	Guar_20#	10000	UNIFRAC Jordan 20/40	1	80800	60
13	Guar_20#	10000	UNIFRAC Jordan 20/40	1.5	95800	60
14	Guar_20#	10000	UNIFRAC Jordan 20/40	2	115800	60
15	Guar_20#	8000	UNIFRAC Jordan 20/40	3	139800	60
16	Guar_20#	8000	UNIFRAC Jordan 20/40	4	171800	60
17	Guar_20#	6000	SuperDC 20/40	4	195800	60
18	Slickwater	9275	-	0	195800	60

Table A-5: Stimulation Pump Schedule for Fat Finish Design

NAME: Fat Finish STAGE COUNT: 10						
Stage	**Fluid**	**Volume (Gallons)**	**Proppant**	**Prop. Conc. (PPG)**	**Cum. Prop. (LBS)**	**Rate**
1	Slickwater	2000	-	0	0	20
2	15% HCl Acid	2000	-	0	0	70
3	Slickwater	15000	-	0	0	70
4	Slickwater	10000	UNIFRAC Jordan 100 Mesh	0.5	5000	70
5	Guar_15#	20000	-	0	5000	70
6	Guar_15#	20000	UNIFRAC Jordan 30/50	1	25000	70
7	Guar_15#	17500	UNIFRAC Jordan 30/50	1.5	51250	70
8	Guar_15#	15000.01	UNIFRAC Jordan 30/50	2	81250.02	70
9	Guar_15#	12500	UNIFRAC Jordan 30/50	2.5	112500.01	70
10	Guar_15#	12500	UNIFRAC Jordan 16/30	3	150000.02	70
11	Guar_15#	1260	-	0	150000.02	70
12	Slickwater	9500	-	0	150000.02	70

Table A-6: Stimulation Pump Schedule for Elite Design

NAME: Elite STAGE COUNT: 13						
Stage	**Fluid**	**Volume (Gallons)**	**Proppant**	**Prop. Conc. (PPG)**	**Cum. Prop. (LBS)**	**Rate**
1	15% HCl Acid	2000	-	0	0	10
2	Slickwater	1000	-	0	0	10
3	15% HCl Acid	5000	-	0	0	40
4	Guar_15#	15200	-	0	0	70
5	Guar_15#	5000	UNIFRAC Jordan 100 Mesh	0.25	1250	70
6	Guar_15#	7500	UNIFRAC Jordan 100 Mesh	0.5	5000	70
7	Guar_15#	10000	UNIFRAC Jordan 100 Mesh	0.75	12500	70
8	Guar_15#	12500	UNIFRAC Jordan 100 Mesh	1	25000	70
9	Guar_15#XL	15200	-	0	25000	70
10	Guar_15#XL	10000	UNIFRAC Jordan 20/40	0.25	27500	70
11	Guar_15#XL	10000	UNIFRAC Jordan 20/40	0.5	32500	70
12	Guar_15#XL	10000	UNIFRAC Jordan 20/40	0.75	40000	70
13	Guar_15#XL	10000	UNIFRAC Jordan 20/40	1	50000	70
14	Guar_15#XL	10000	UNIFRAC Jordan 20/40	1.5	65000	70
15	Guar_15#XL	15000	UNIFRAC Jordan 20/40	2	95000	70
16	Guar_15#XL	18000	UNIFRAC Jordan 20/40	2.5	140000	70
17	Guar_15#XL	10000	UNIFRAC Jordan 20/40	3	170000	70
18	Guar_15#XL	2500	-	0	170000	70

19	Slickwater	16800	-	0	170000	70

Table A-7: Stimulation Pump Schedule for More PPG Design

NAME: More PPG STAGE COUNT: 10						
Stage	**Fluid**	**Volume (Gallons)**	**Proppant**	**Prop. Conc. (PPG)**	**Cum. Prop. (LBS)**	**Rate**
1	Slickwater	2000	-	0	0	20
2	15% HCl Acid	2000	-	0	0	70
3	Slickwater	15000	-	0	0	70
4	Slickwater	10000	UNIFRAC Jordan 100 Mesh	0.5	5000	70
5	Guar_15#	20000	-	0	5000	70
6	Guar_15#	20000	UNIFRAC Jordan 30/50	1	25000	70
7	Guar_15#	17500	UNIFRAC Jordan 30/50	1.5	51250	70
8	Guar_15#	15000	UNIFRAC Jordan 30/50	2	81250	70
9	Guar_15#	12500	UNIFRAC Jordan 30/50	2.5	112500	70
10	Guar_15#	12500	UNIFRAC Jordan 30/50	3	150000	70
11	Guar_15#	12500	UNIFRAC Jordan 30/50	4	200000	70
12	Guar_15#	1260	-	0	200000	70
13	Slickwater	9500	-	0	200000	70

Table A-8: Stimulation Pump Schedule for Riley Design

NAME: Riley STAGE COUNT: 10						
Stage	**Fluid**	**Volume (Gallons)**	**Proppant**	**Prop. Conc. (PPG)**	**Cum. Prop. (LBS)**	**Rate**
1	15% HCl Acid	2000	-	0	0	10
2	Slickwater	1000	-	0	0	10
3	15% HCl Acid	5000	-	0	0	40
4	Guar_15#	15200	-	0	0	70
5	Guar_15#	5000	UNIFRAC Jordan 100 Mesh	0.25	1250	70
6	Guar_15#	7500	UNIFRAC Jordan 100 Mesh	0.5	5000	70
7	Guar_15#	10000	UNIFRAC Jordan 100 Mesh	0.75	12500	70
8	Guar_15#	12500	UNIFRAC Jordan 100 Mesh	1	25000	70
9	Guar_15#XL	15200	-	0	25000	70
10	Guar_15#XL	10000	UNIFRAC Jordan 20/40	0.25	27500	70
11	Guar_15#XL	10000	UNIFRAC Jordan 20/40	0.5	32500	70
12	Guar_15#XL	10000	UNIFRAC Jordan 20/40	0.75	40000	70
13	Guar_15#XL	10000	UNIFRAC Jordan 20/40	1	50000	70
14	Guar_15#XL	10000	UNIFRAC Jordan 20/40	1.5	65000	70
15	Guar_15#XL	15000	UNIFRAC Jordan 20/40	2	95000	70
16	Guar_15#XL	18000	UNIFRAC Jordan 20/40	2.5	140000	70
17	Guar_15#XL	10000	UNIFRAC Jordan 20/40	3	170000	70

18	Guar_15#XL	2500	-	0	170000	70
19	Slickwater	9500	-	0	170000	70

Table A-9: Stimulation Pump Schedule for Well A Design

NAME: Well A STAGE COUNT: 10						
Stage	**Fluid**	**Volume (Gallons)**	**Proppant**	**Prop. Conc. (PPG)**	**Cum. Prop. (LBS)**	**Rate**
1	Slickwater	630	-	0	0	20
2	15% HCl Acid	2016	-	0	0	20
3	Slickwater	1008	-	0	0	75
4	15% HCl Acid	4998	-	0	0	75
5	Guar_15#	10038	-	0	0	75
6	Guar_15#	10122	UNIFRAC Jordan 100 Mesh	0.25	2531	75
7	Guar_15#	9996	-	0	2531	75
8	Guar_15#	10248	UNIFRAC Jordan 100 Mesh	0.5	7655	75
9	Guar_15#	15036	-	0	7655	75
10	Guar_15#	10458	UNIFRAC Jordan 100 Mesh	1	18113	75
11	Guar_15#	24990	-	0	18113	75
12	Guar_15#	15666	Badger Sand 40/70	1	33779	75
13	Guar_15#XL	10290	-	0	33779	75
14	Guar_15#XL	10962	Badger Sand 40/70	2	55703	75
15	Guar_15#XL	14112	UNIFRAC Jordan 30/50	2	83927	75
16	Guar_15#XL	15120	UNIFRAC Jordan 30/50	2.5	121727	75
17	Guar_15#XL	13020	UNIFRAC Jordan 30/50	3	160786	75

18	Guar_15#XL	420	-	0	160786	75
19	Slickwater	8820	-	0	160786	75

Table A-10: Stimulation Pump Schedule for Well B Design

NAME: Well B STAGE COUNT: 10						
Stage	**Fluid**	**Volume (Gallons)**	**Proppant**	**Prop. Conc. (PPG)**	**Cum. Prop. (LBS)**	**Rate**
1	Slickwater	1000	-	0	0	20
2	15% HCl Acid	2000	-	0	0	60
3	Slickwater	1050	-	0	0	60
4	15% HCl Acid	5000	-	0	0	60
5	Guar_15#	10000	-	0	0	60
6	Guar_15#	10000	White Frac 100 Mesh	0.25	2500	60
7	Guar_15#	10000	-	0	2500	60
8	Guar_15#	10000	White Frac 100 Mesh	0.5	7500	60
9	Guar_15#	15000	-	0	7500	60
10	Guar_15#	10000	White Frac 100 Mesh	0.75	15000	60
11	Guar_15#	20000	-	0	15000	60
12	Guar_15#	10400	White Frac 100 Mesh	1	25400	60
13	Guar_15#XL	24300	-	0	25400	60
14	Guar_15#XL	15000	Badger Sand 40/70	1	40400	60
15	Guar_15#XL	10000	Badger Sand 40/70	2	60400	60
16	Guar_15#XL	15000	UNIFRAC Jordan 30/50	2	90400	60
17	Guar_15#XL	14000	UNIFRAC Jordan 30/50	2.5	125400	60

18	Guar_15#XL	10000	ATLAS CRC-C 30/50	3	155400	60
19	Guar_15#XL	420	-	0	155400	60
20	Slickwater	10500	-	0	155400	60

Table A-11: Stimulation Pump Schedule for Well C Design

NAME: Well C STAGE COUNT: 10						
Stage	**Fluid**	**Volume (Gallons)**	**Proppant**	**Prop. Conc. (PPG)**	**Cum. Prop. (LBS)**	**Rate**
1	Slickwater	1100	-	0	0	20
2	15% HCl Acid	2000	-	0	0	60
3	Slickwater	1300	-	0	0	60
4	15% HCl Acid	5000	-	0	0	60
5	Guar_15#	10000	-	0	0	60
6	Guar_15#	10000	White Frac 100 Mesh	0.25	2500	60
7	Guar_15#	10000	-	0	2500	60
8	Guar_15#	10000	White Frac 100 Mesh	0.5	7500	60
9	Guar_15#	10000	-	0	7500	60
10	Guar_15#	10200	White Frac 100 Mesh	0.75	15150	60
11	Guar_15#	10000	-	0	15150	60
12	Guar_15#	10000	White Frac 100 Mesh	1	25150	60
13	Guar_15#XL	10000	-	0	25150	60
14	Guar_15#XL	10000	Badger Sand 40/70	1	35150	60
15	Guar_15#XL	7500	Badger Sand 40/70	2	50150	60
16	Guar_15#XL	10000	UNIFRAC Jordan 30/50	2	70150	60
17	Guar_15#XL	12000	UNIFRAC Jordan 30/50	2.5	100150	60

18	Guar_15#XL	9000	ATLAS CRC-C 30/50	3	127150	60
19	Guar_15#XL	420	-	0	127150	60
20	Slickwater	10500	-	0	127150	60

Table A-12: Stimulation Pump Schedule for Well D Design

NAME: Well D STAGE COUNT: 12						
Stage	**Fluid**	**Volume (Gallons)**	**Proppant**	**Prop. Conc. (PPG)**	**Cum. Prop. (LBS)**	**Rate**
1	Slickwater	945	-	0	0	20
2	15% HCl Acid	2000	-	0	0	80
3	Slickwater	1000	-	0	0	80
4	15% HCl Acid	5000	-	0	0	80
5	Slickwater	10000	-	0	0	80
6	Slickwater	20000	White Frac 100 Mesh	0.5	10000	80
7	Slickwater	20000	White Frac 100 Mesh	0.75	25000	80
8	Slickwater	20000	White Frac 100 Mesh	1	45000	80
9	Slickwater	20000	White Frac 100 Mesh	1.25	70000	80
10	Slickwater	20000	White Frac 100 Mesh	1.5	100000	80
11	Guar_15#	20000	UNIFRAC Jordan 20/40	0.5	110000	80
12	Guar_15#	20000	UNIFRAC Jordan 20/40	0.75	125000	80
13	Guar_15#	20000	UNIFRAC Jordan 20/40	1	145000	80
14	Guar_15#	20000	UNIFRAC Jordan 20/40	1.25	170000	80
15	Guar_15#	20000	UNIFRAC Jordan 20/40	1.5	200000	80
16	Guar_15#	18000	UNIFRAC Jordan 20/40	2	236000	80
17	Guar_15#XL	16000	UNIFRAC Jordan 20/40	2.5	276000	80

18	Guar_15#XL	10000	UNIFRAC Jordan 20/40	3	306000	80
19	Guar_15#XL	1260	-	0	306000	80
20	Slickwater	10000	-	0	306000	80

VITA

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