PRIORITIZING WORKOVER OPTIONS PROBABILISTICALLY IN A MARGINAL OIL FIELD: A CASE STUDY FROM THE PERMIAN BASIN

A Thesis

by

JOHN LAUGHLIN DENMAN III

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Chair of Committee,	Ruud Weijermars
Committee Members,	Maria Barrufet
	George Voneiff
Head of Department,	Dan Hill

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ABSTRACT

This study proposes a probabilistic decision-making support model ("Green Tree"), created in Microsoft Excel, to assist operators of marginal assets in prioritizing well workover decisions. Such a tool can help operators of legacy, low volume oil and gas assets to maximize their asset value by allocating capital towards the best well workover options to achieve equitable production increases. The framework for this model was constructed by following interventions taken in a marginal oil field in the Permian Basin from the time it was acquired in 2013 through 2016. The Green Tree decision model quantifies historic uncertainty in outcomes and uses the probabilistic present values of all interventions to display the optimum path value in a decision tree. Relatively few inputs are needed for the decision tree to show an optimum intervention path. These inputs include historic production data for the field, service costs for each wellbore workover, anticipated production increase from each workover, and expected probabilities for each intervention based off of the operator's historical results. Once the inputs have been entered, the user is able to manually adjust the projected commodity prices and see the corresponding changes in the optimum path value. The Green Tree is applied to the permian basin asset to identify the optimum sequence of interventions, revealing the risk adjusted upside to the base case PV10 for the field calculated in the workbook. A summation of the expected monetary values (EMVs) from several interventions can be used to estimate the total upside value to the asset owner. The tool developed here may benefit marginal well producers in evaluating asset value when

looking at an acquisition or divestiture. Lastly, posterior probabilities can be used in this model as the results of actual workovers in the field are examined, adjusting the tree in real time to account for any changes in the outcome of probabilities or production responses.

DEDICATION

Soli Deo Gloria

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Contributors

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All work for the thesis was completed by the student, under the advisement of Dr. Ruud Weijermars of the Department of Petroleum Engineering.

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1. INTRODUCTION

Since the early days of the commercial oil and gas industry, operators have deliberated on best practices for extending well life by selecting the optimal intervention to prolong profitability in marginally economic wellbores. Many oil and gas operators across the U.S. hold assets that are sub-economic and are regularly forced to evaluate the options of spending CAPEX on wellbore interventions to improve production, plugging underperforming wellbores, or divesting the assets. While all operators approach these decisions with a desire to maximize profitability, few companies take a systematic methodology towards risk adjusted decision making.

Many definitions exist for marginal and stripper wells as nearly every company or government agency that uses these terms has their own definition. Three main groups exist that each use different definitions for marginal and stripper wills: (1) the Interstate Oil and Gas Compact Commission (IOGCC), (2) the U.S. Energy Information Agency (EIA), and (3) the definitions found in much of the published literature on marginal assets. The IOGCC, which is a multi-state quasi government group that advocates for maximizing domestic oil and gas production, defines a marginal well “as a well that requires a higher product price to be worth producing, due to either low production rates and/or high production costs” (IOGCC, 2015, p. 3). This means that each oil or gas well has a breakeven product price, which once the price falls below this threshold, the wellbore is considered marginal. (1) In order to simplify the determination of a marginal well, the IOGCC considers any oil well with 10 bbls of oil per day or less or any gas well with 60 Mcf per day or less to be considered as marginal or stripper status (IOGCC, 2015, p. 2). (2) The EIA defines a stripper or marginal well as "an oil well producing no more than 15 barrels of oil equivalent per day over a 12 month period or a gas well producing no more than 90,000 cubic feet per day over a 12-month period" (EIA, 2016). Thus EIA statistics on marginal wells will include a greater number of wells than the IOGCC due to their more inclusive definition. (3) Lastly, many publications on marginal assets primarily reference offshore fields when referring to marginal assets and provide a variety of definitions. These definitions will not be discussed at length as the focus of this paper is onshore U.S. marginal assets.

A key task of the IOGCC is to champion the preservation of America's marginal oil and gas wells; one means by which they seek to do this is by publishing a bi-yearly report compiling the impact of marginal wells across the United States. The IOGCC 2015 Report on marginal wells estimates that marginal wells have produced 2.85 billion barrels of oil and 19.9 Mcf of natural gas over the past ten years, adding over $300 billion in production value to the U.S. economy (p. 5). In 2015, these marginal wells contributed 8.5% of total oil production and 7.0% of total natural gas production in the U.S. (IOGCC, 2015, p. 23). Thus marginal oil and gas assets hold large quantities of recoverable reserves and tremendous value, so ensuring their profitable production should not only be a top priority for all operators, but also for the energy security of the United States. With low commodity prices projected by the EIA to continue over the next few years, many of these marginal assets could be prematurely plugged and abandoned, leaving significant volumes of recoverable hydrocarbons forever trapped

(EIA, 2016). The EIA projects that worldwide demand for oil and gas will grow by 1.4% per year over the next forty years, leading to a continued price recovery as demand outpaces supply (EIA, 2016). A demand driven price recovery could in turn push many wells considered marginal today back into the profitable category for many years to come. It is more important than ever for marginal well operators to make informed operating decisions that seek to grow reserves in a profitable way.

While marginal wells play a significant role in the U.S. energy production landscape, very little published material exists to assist marginal well operators in seeking clarity on intervention decisions. Several conference papers published through SPE in 2005 address specific operating issues related to marginal or stripper wells and many other papers have been published addressing topics such as dewatering stripper gas wells, calculating reserves in stripper fields, and preserving reserves life in stripper wells. Yet none of these papers provide a mention of addressing uncertainty or projecting the economic value for possible operating interventions.

This report seeks to begin a dialogue amongst marginal well operators seeking to maximize the value of their assets by proposing a simple, but powerful decision making tool for evaluating intervention selection as well as the upside value of any future intervention, all of which are risk adjusted based on historical probabilities. This template is validated by use of a case study from a marginal field in the Permian basin. This decision tree template, known as “Green Tree”, has been created for use in legacy oil fields to aid operators in selecting the optimal field intervention and for determining the right value to place on future interventions in the field when considering an acquisition or divestiture. Once interventions have been completed, the Green Tree can also be used to apply posterior probabilities as well as determine the value of the other non-optimal branches.

The case study in this report uses actual field data from a marginal oil field in the Permian basin. According to the EIA, the Permian basin held an estimated 722 million barrels of proved reserves in 2013 and contributed to nearly 15 percent of total U.S. production (EIA, 2015). This mammoth basin is one of the oldest and largest areas in the U.S. for petroleum production. It holds several prolific production intervals and continues to see an abundance of drilling activity nearly 100 years after the first commercial well. The marginal field used as a case study in this report is called the South Cowden field and it is located in the Grayburg reservoir on the eastern edge of the central basin platform. Several field interventions have been implemented successfully in this field, and were used to aid in the development of the Green Tree. While the interventions selected in this field were selected before the development of this decision making framework, the economics and interventions have been placed into the tree in order to showcase the effectiveness of this tool. This case study reveals the significant economic gains that can be obtained by investors from the right marginal assets if proper interventions are selected.

2. FRAMING THE PROBLEM AND METHODOLOGY OF SOLUTION

Low volume marginal wells make up nearly 70% of the active wellbores in the U.S., and are owned by companies as large as multinational oil conglomerates and as small as independent operators who operate as few as ten wells (IOGCC, 2015). These marginal wells play a significant role in the U.S. energy production landscape and many papers have been published addressing nearly every aspect of marginal well production. While these reports address many of the specific operating challenges to profitably managing marginal wells, no known research to date has addressed quantifying uncertainty, selecting optimal workover options and assigning proper upside value through use of a decision tree. It is also important for the reader to understand the principles of a decision tree, and how a decision tree is applied to the issues addressed in this report.

2.1 Previous Research on Marginal Well Operation

Numerous high-quality research reports and industry discussions involving the operation of marginal (and stripper) wells have been published dating back to the 1930s. The vast majority of this published material on marginal assets focuses on a single aspect of marginal well production, with no known published material covering improved decision making in marginal oil fields. The closest paper to this topic came out in a 2005 SPE conference paper from MacDonald, Frantz, Covatch, Zagorski, and Forgione titled “A Rapid and Efficient Method To Identify Underperforming Stripper Gas and Oil Wells”. This paper sought to answer and assist stripper well operators in maximizing production from low-productivity wells by developing a software to identify remediation potential in stripper wells. The development of this software was a joint effort between Schlumberger and the DOE, and the software they developed was called Stripper Well Analysis Remediation Methodology or SWARM. Underperforming wells were identified in the software if their average production rates were less than a specified radius of wells around the selected well. While this software proved successful at identifying underperforming wells, it required historic production data for each individual well in the field and it did not aid the operator in determining which intervention should be selected or in seeing the effect each intervention will have on overall NPV under varying commodity prices.

A number of papers focused specifically on stripper gas wells, such as: Reeves and Walsh's 2003 paper, "Selection and Treatment of Stripper Gas Wells For Production Enhancement, Mocane-Laverne Field, Oklahoma", Gaskill's 2005 paper on "Stripper Gas-Well Production Optimization and Reserve Retention", and James, Huck, and Knobloch's 2001 paper titled "Low Cost Methodologies to Analyze and Correct Abnormal Production Decline In Stripper Gas Wells". Each of these papers provided real field data to support their suggested techniques for improving the production and profitability of stripper gas wells, primarily focusing on the issue of de-watering low volume gas wells. These papers represent only a small sampling of the many papers relating to production techniques in low volume gas wells. While this research does address specific issues common to marginal gas wells, it does not provide suggestions for quantifying the historic uncertainty when selecting interventions or for assigning an economic value to each well workover.

Other published material has focused on reserves relating to marginal assets, such as the Lefkovits and Matthews 1958 paper titled: “Application of Decline Curves to Gravity-Drainage Reservoirs in the Stripper Stage” and their 1956 paper titled “Gravity Drainage Performance of Depletion-Type Reservoirs in the Stripper Stage”. Their 1956 paper focuses on gas reservoirs with such low pressure that gravity is the primary driving force during production, while their 1958 paper sought to apply previously developed curves for a hyperbolic decline in a homogenous gravity-drainage reservoir to similar fields in the stripper stage of production. Gitman, Watson, and Johnson, also came out with a paper titled: “Near-Wellbore Damage Remediation in Stripper Wells” in 2005 that used full scale reservoir models developed in CMG software to determine the most efficient manner to enhance oil recovery in stripper wells by reducing wellbore damage. They determined that the most effective method to increase cumulative production was not through near wellbore damage remediation, but through re-pressurization of the reservoir.

There appears to have a been a concentrated focus within SPE to focus on stripper wells in the year 2005, as a great number of conference papers on stripper wells were published for SPE in 2005. These papers include “Beating the Marginal Well Performance in a Mature Field: San Francisco Field in Colombia” by Suarez, Gaviria, Pavas, and Frorup, 2005, “Investigation of New Tool to Unload Liquids from Stripper-Gas Wells” by Ali, Scott, and Fehn, 2005, “Economic Sand Control and Stimulation

Strategy for Marginal Wells with Limited Reserves" by Morrison & Smith, 2005, and many more. Few, if any, papers covering stripper or marginal production have been published since 2005, as much of the research focus has now turned to unconventional activities.

Several organizations exist to promote the continued study and development of stripper wells, such as the Interstate Oil and Gas Compact Commission, the National Stripper Well Association, and the Stripper Well Consortium. As previously mentioned in this report, the IOGCC was chartered by congress in 1935 with the goals of helping states to maximize domestic oil and natural gas production, minimize the waste of irreplaceable natural resources, and protect human and environmental health (IOGCC, 2015). Their primary role today is to unite the governors of their member states to lobby congress with a unified voice supporting the preservation and development of oil and gas assets. The National Stripper Well Association began in 1934, and also serves primarily as a lobbying organization on behalf of the small stripper well operators. The National Stripper Well Association does hold annual meetings for its industry members as well as have state chapters that promote collaboration and lobbying on a more local scale. The Stripper Well Consortium was established with the help of the DOE and Pennsylvania State University in 2000 to help "develop and demonstrate technologies that will improve the production performance of stripper wells" (Covatch & Morrison, 2005). This organization proved fruitful in drawing industry participation for many years by helping to develop and support new technologies for marginal well operators, but has suffered at the hands low commodity prices and fell dormant in 2014. While these organizations are a helpful tool for promoting collaboration and raising awareness for marginal well operators, there are no known organizations supporting a dialogue amongst these operators with a focus on profitable production practices.

The existing literature and industry organizations appear void of proposals for enhanced decision making in marginal fields with reduced uncertainty. There do not appear to be any studies providing techniques for assigning upside value in a potential acquisition or divestiture of a marginal field, or for altering upside assumptions after results from interventions have been achieved using Bayesian analysis.

2.2 Generic Decision Tree Overview

Decision trees are often used when a problem contains a large number of interrelated elements, making the problem appear very complicated and thus reducing a decisions maker's ability to link outcomes to a given decision (Mian, 2011, p. 167). A decision trees seeks to provide a lucid visual structure for any complicated problem, thus easing the ability to convey complicated information to others in a clean and precise manner (Mian, 2011, p. 167). The optimal path in a tree is a determined by the highest Expected Monetary Value or "EMV" of each outcome. The EMV most commonly used, is calculated by weighing the NPV of a certain outcome by its given probability (Mian, 2011, p. 132). Each possible outcome has its own EMV, which is discounted as it moves to the left through progressive chance and decision nodes until it reaches the primary branches on the tree. The optimal path for each tree is chosen by starting with the primary branches on the left side of the tree and progressively moving to the right by choosing the branch with the highest EMV until a branch has been exhausted and an option chosen. An example of a basic decision tree built to display a “Drill or Don’t Drill” decision can be found in Figure 1 below.

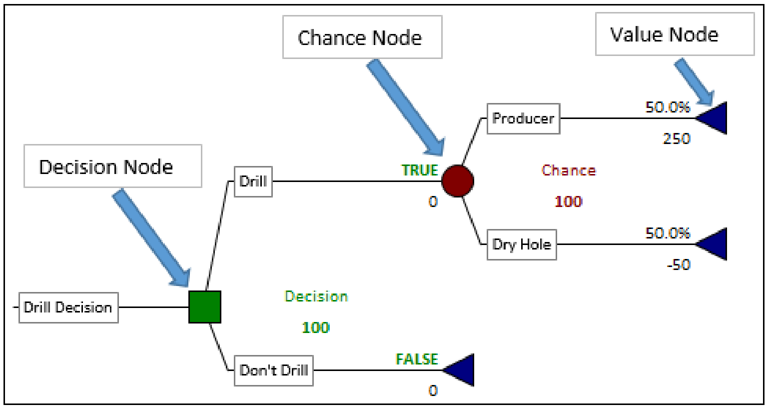


Figure 1. Example Decision Tree

This simple example shows the NPV for a producer as $250 and for a Dry Hole as -$50. The PrecisionTree software then calculates the EMV by multiplying each NPV by its probability of occurring (50%) and sums the results, yielding an EMV of $100. Since the EMV is a positive value and greater than the $0 provided by the “Don’t Drill” option, the PrecisionTree software marks the “Drill” option as the optimal path. The spreadsheet created to analyze marginal fields used Microsoft Excel 2013, as well as the Excel plug-in PrecisionTree7, to build and operate the decision tree and all of its inputs.

2.3 Marginal Well Application

The decision tree and accompany spreadsheet created for this report can serve two main purposes for an operator. *First,* it will aid an operator of a recently acquired marginal oil and gas field in making informed intervention decisions by applying probabilities and NPVs to each possible intervention. A “best estimate” probability for each intervention is determined from a combination of historical success and the user's experience, the results of which are input into the spreadsheet in order to calculate the probability of each possible chance node on the tree. A base case NPV for the field is calculated using a decline curve fit to historical production data in the spreadsheet, and then the expected increase in NPV for each intervention is added (or subtracted) from this base case value to provide a field level NPV value for each possible outcome. The tree will then calculate the EMV of each branch and direct the operator towards the optimum path showing the preferred intervention with the highest EMV that should first be pursued by the company. Since operators are not limited to pursuing a single intervention at one time, this template tree can be used to determine secondary, tertiary, and so on, preferred interventions by eliminating the values from the optimal intervention and allowing the tree to calculate a new optimum path with the highest EMV. After a certain intervention has been executed, the Bayesian knowledge obtained from the outcome can be used to create an updated decision tree with reduced uncertainty. This process of dynamic updates can continue until all available options are exhausted and the operator begins to weigh the value of divesting the field. Each dynamic update added to the decision tree will either increase or decrease the EMV for the upside value of the bid decision. It is then the operator's responsibility to keep accurate records of the costs and results from all interventions conducted in any operated field in order to aid the operator in predicting more accurate probabilities as it enters new fields in the future. This historical data can be used when evaluating a potential acquisition as well as a field where interventions are already taking place.

The *second* purpose of this decision tree template is to aid an operator in assigning proper "upside" value to a bid price for a marginal oil and gas field. As previously discussed, the operator can use knowledge gained during due diligence in the field as well as previous operating knowledge from other fields to assign probabilities and NPVs to each possible intervention in the tree (the number and type of possible interventions can be manually adjusted by the operator for a specific field). The bidding operator can then chose to aggregate the EMVs from each intervention, apply a chosen discount to this value, and use it a bid price. The upside NPV is added to the base case NPV which is also determined as the first step in the spreadsheet by use of a decline curve to project 40 years of production data. All economic inputs and operating expenses can be applied to the forecasted production in order to provide an accurate economic forecast for this field.

A sensitivity analysis to commodity price can be performed in the tree for the base case reserves estimate as well as for each intervention, enabling the user to analyze the optimal intervention for each commodity price scenario. The predicted cumulative oil recovery per well as a result of these workovers as well as service costs can be adjusted for any intervention. Optimum paths are likely to shift based upon the EMV impact of oil and gas price scenarios, service costs, and predicted oil or gas recovery from each intervention.

3. CURRENT STATE OF THE SOUTH COWDEN FIELD

When an operator assesses a potential acquisition, the value of the remaining reserves as well as any potential upside or gains from expense reductions will be evaluated. The potential acquirer will also look for pertinent reservoir data and information on the field history in order to determine the primary reservoir characteristics that could lend themselves to successful wellbore workovers. The better the operator can understand the reservoir the better production and exploitation engineering the firm can provide. The South Cowden Field in the Permian basin was a neglected legacy asset belonging to a large operator who sold it to the current operator in late 2013. From the offset, the current operator sought to understand the reservoir and the production history of the field in order to determine wellbore interventions with the lowest amount of risk and greatest amount of production increase. Over the three years since the field was purchased, significant economic gains have been achieved through various capital expenditures on field interventions. The interventions made over the last three years in this field serve as the basis for the ensuing decision tree model and all costs and probabilities used in section 4 come from best estimates in this field.

3.1 Geologic Setting and Field History

The South Cowden oil field, located on the eastern edge of the central platform in the Permian Basin, contains three actively producing formations: the Grayburg, the Canyon, and the Ellenburger. Company files show that the Grayburg, which is the primary producing interval and will be the focus of this report, was first discovered in the late 1930s and commercial production began in 1941. Figure 2 shows the location of the South Cowden field on the eastern edge of the central basin platform in Ector County.

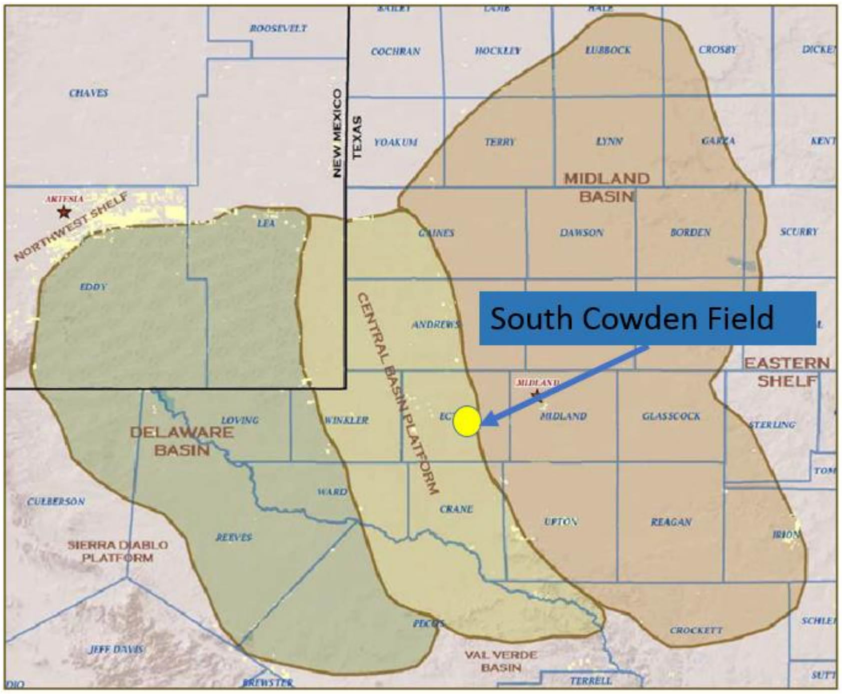


Figure 2. Map of South Cowden Field (source: www.shaleexperts.com)

The stratigraphic column for the Permian basin can be seen in Figure 3 below, with boxes highlighting the productive formations in the South Cowden field. While other reservoirs have been productive in the past in this field, the only reservoirs under production today are the Grayburg, Canyon, and Ellenburger (highlighted in Figure 3).

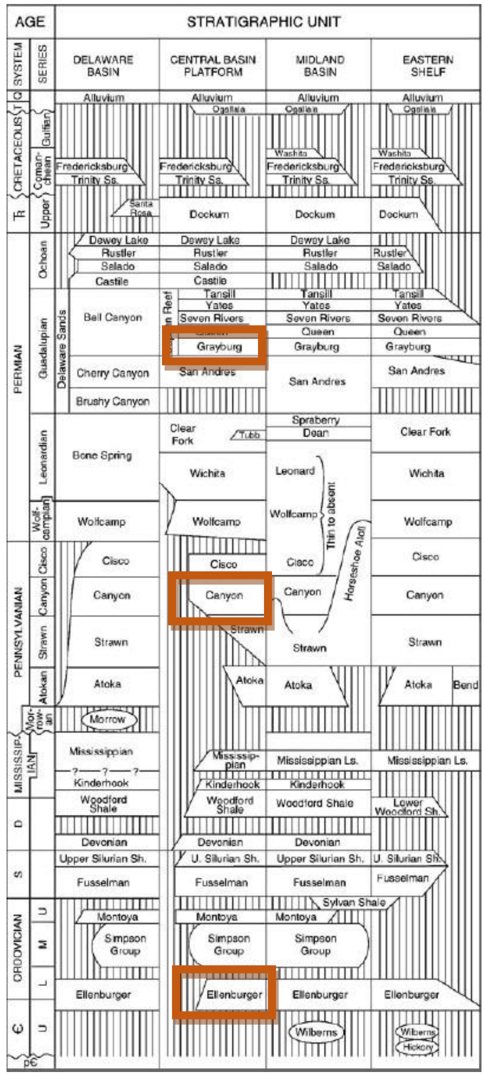


Figure 3. Permian Stratigraphic Unit (source: www.shaleexperts.com)

The Permian basin is known for its prolific production of hydrocarbons from a multitude of different producing horizons depending on a well's location in the basin. As Figure 3 shows, the Delaware basin, Midland basin, and Eastern shelf, contain many of the same productive intervals as the central basin platform, but geologic properties in each of these zones changes significantly across the basin. A 1982 Railroad Commission report provides many of the basic reservoir properties for the portion of the Grayburg located on the central basin platform, which can be found in Table 1 below.

Reservoir Depth:	4050 ft
Average Effective Porosity:	6.0%
Average Horizontal Permeability:	2.0 mD
Average Net Pay:	65 ft
Oil Gravity:	35° API
Original Reservoir Pressure:	1760 psi
Productive Acres in Reservoir:	21,600 acres
Original Drive Mechanism:	Solution Gas

Table 1. Grayburg Reservoir Properties

Geologic reports owned by the company show that the Grayburg carbonate strata was deposited in open to restricted platforms on the eastern edge of the central basin platform and the primary reservoir facies are dolomitized carbonates with severe heterogeneity. Combinations of structural and stratigraphic trapping mechanisms hold the hydrocarbons in place, with the reservoir dipping to the south and to the east. While solution gas was the drive mechanism during primary production, well files show that reservoir pressure declined rapidly and many wells were placed on artificial lift only months after being drilled. Many of the initial wells drilled in the 1940s in this tight, low pressure reservoir were stimulated in the open hole with use of nitroglycerin, often called “barefoot completions”. Initial 24hr production rates varied from 46 – 960 BOPD in response to these stimulations. These wells were originally drilled on 40 acre spacing, but later in the 1950s and 1960s wells were downsized to 20 acre spacing. (Several wells were drilled on 10 acre spacing in the 1980s but were not economic). The 1982 Railroad Commission report estimates that 9,640,000 bbls of oil were recovered during primary production.

Due to low permeability and a lack of reservoir pressure, waterflooding was initiated in the field in 1955 when a five spot design was created. More injection wells were added throughout the 1960s, leading to a production peak in early 1968. Historic production for the field was gathered from public data on the Texas Railroad Commission website, which began gathering data for the unitized field in 1955 (see Figure 4). Production before this time was reported on a well by well basis and only a handful of these wells have full production histories dating back to when they were drilled.

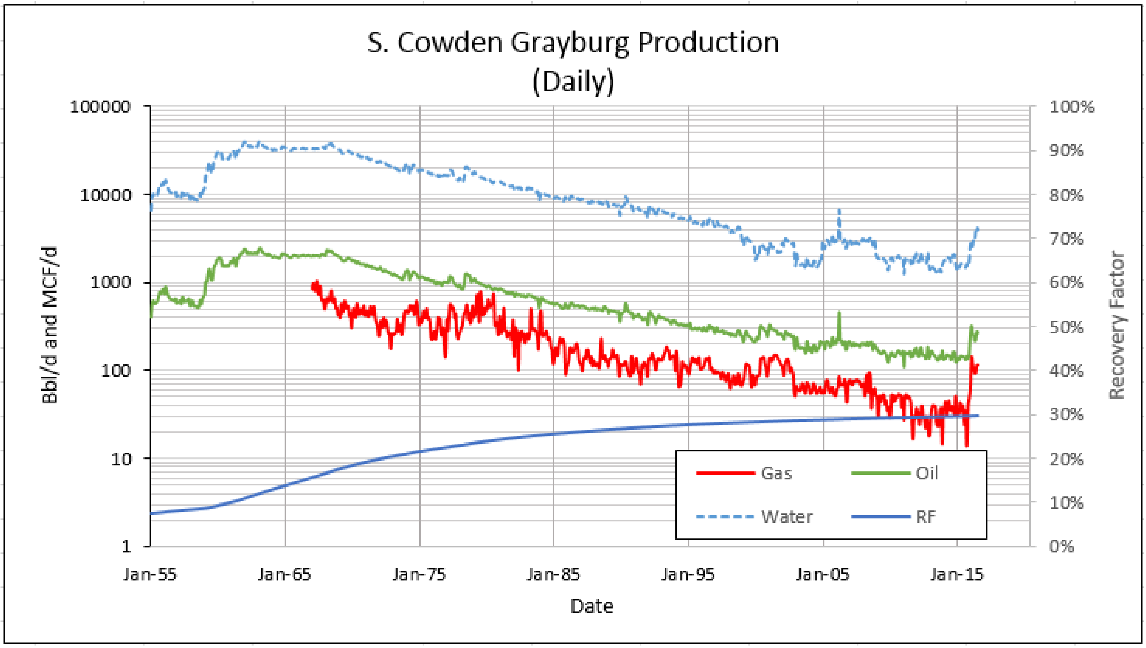


Figure 4. Historic Production for S. Cowden (Grayburg)

While a production response to the waterflood was seen in the field, the severe heterogeneity in the reservoir lead to inconsistent results. Response by well varied from none, to an arrest in decline, to an increase of over 100 BOPD in one well. Nearly all parts of the field saw the effects of the waterflood except for the NW corner of the lease. In the late 1970s and early 1980s the waterflood pattern was redesigned to an alternating line drive which saw a limited production increase in response to this change. At its peak in the 1980s, the Grayburg had over 100 producing oil wells in the field and nearly 60 water injection wells, many of these wells have since been plugged or temporarily abandoned due to wellbore integrity issues or being uneconomic.

Since its initial development in the 1940s, the South Cowden field has been owned by many operators who continued to develop the field through infill drilling and waterflood implementation. The current operator purchased the field in late 2013 when the Grayburg was producing ~110bbls/day of oil from ~40 active oil wells, with minimal associated gas. Figure 5 below shows the lease outline as well as the locations of the active producers and injectors in the field as of 2016. About 85% of these wells are considered stripper wells due to their low production volumes of less than 10 bbls of oil per day. Over the past three years, the operator has sought to cut operating expenses and exploit the reservoir with minimum capital deployed.

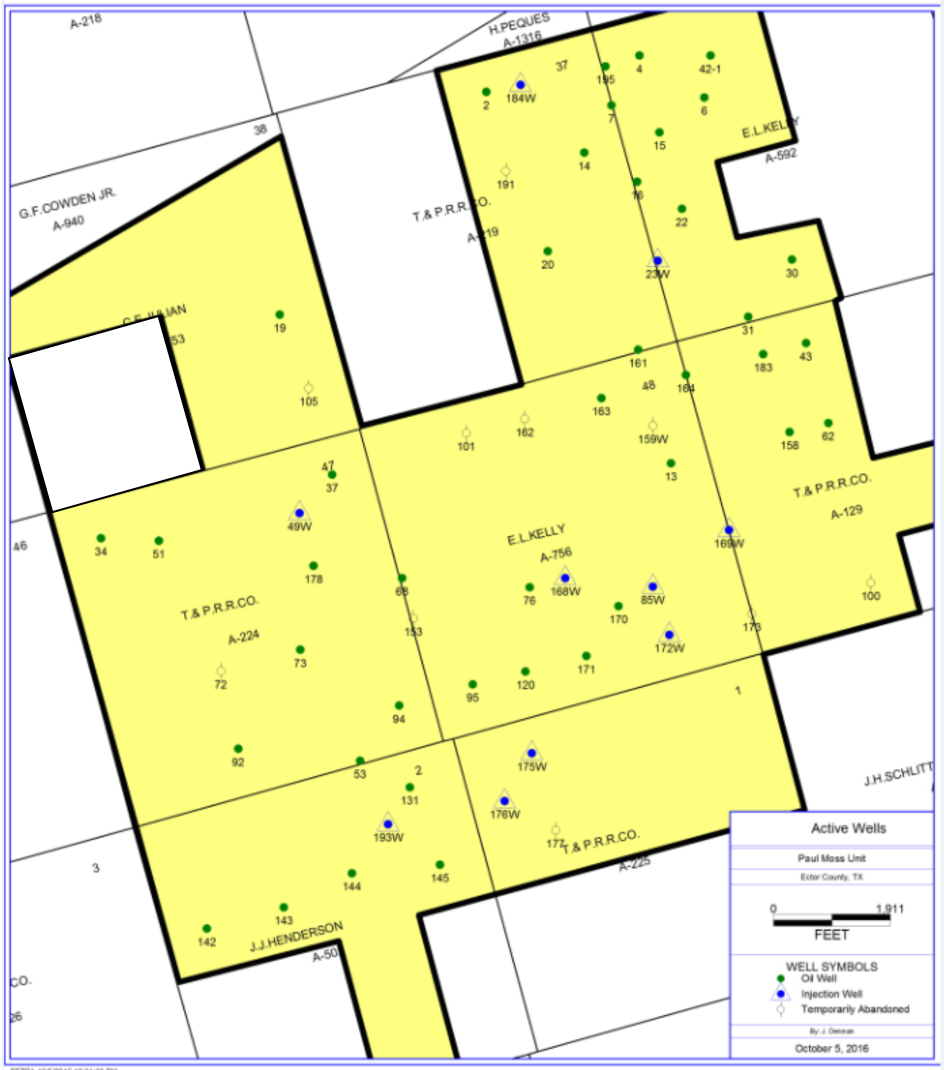


Figure 5. Lease Map and Active Wells for S. Cowden Field

3.2 Past Interventions

In its efforts to determine the best methods to increase production and grow reserves in the field, the current operator conducted an extensive review of well files, searching for successful past interventions. This review alerted the operator to past success in the hydraulic fracturing of wells that had previously been hydraulically fractured, or "re-fracing". The potential for this intervention to be successful was further confirmed by the fact that several injector wells had been converted into economic producers, confirming the heterogeneities present in this tight reservoir. The operator also analyzed the effects and expense of the chemical treatments, as well as many other factors to determine the best way to lower lease operating expenses (LOE).

While the Green Tree model did not exist at this time interventions were pursued in this field, the operator has successfully completed many interventions over the past three years, including: LOE Reductions, Refracs, Adding Compression, Behind Pipe Exploitation, and Infill Drilling. Apart from a thorough review of well files, the operator also build a geologic model of the field in order to better understand the reservoir. This model was built primarily using wellbore logs and core data from wellfiles using Petra Software. The operator also gathered reservoir information from public sources such as the Society of Petroleum Engineers (SPE) and the American Association of Petroleum Geologists (AAPG). An example of a Grayburg structure map that was built using Petra software can be found in Figure 6 below.

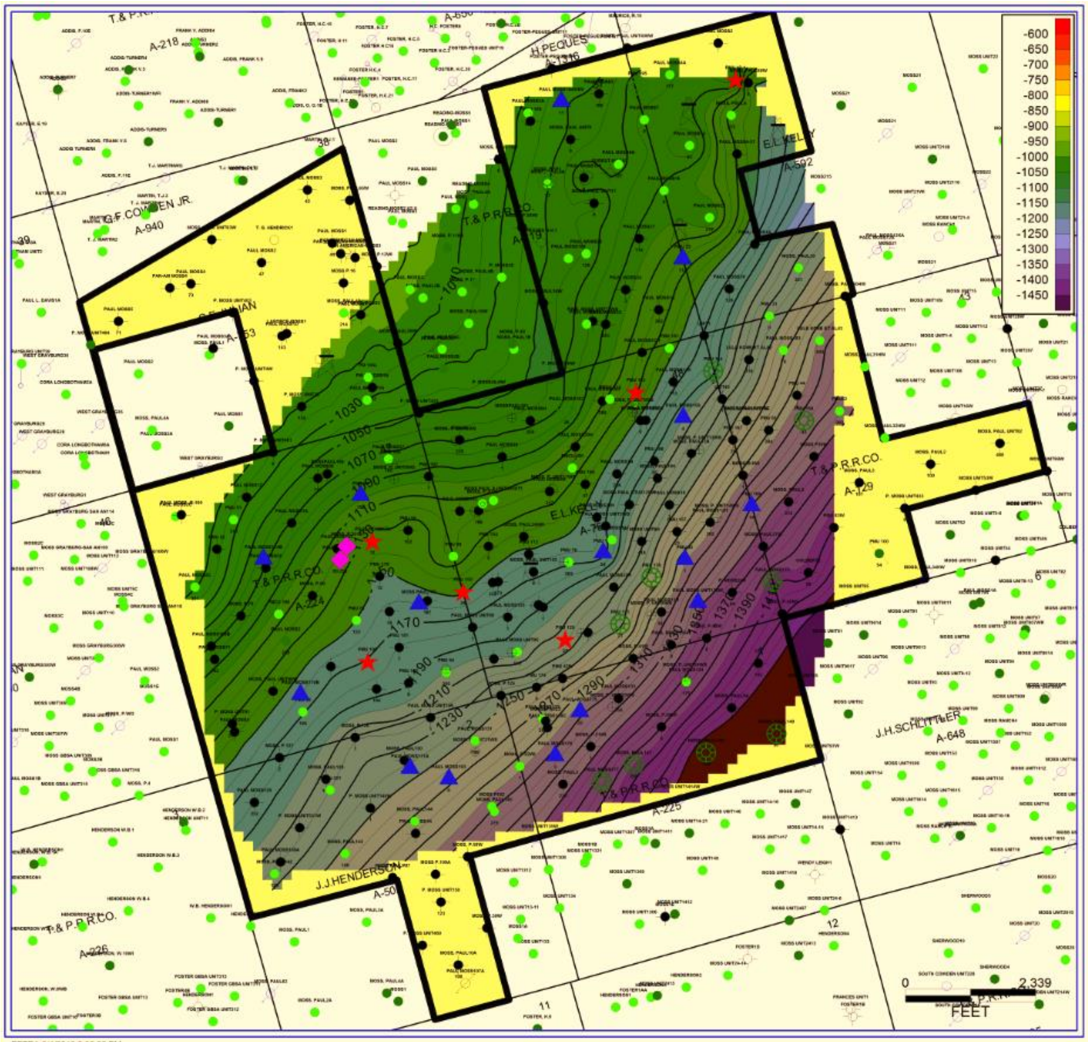


Figure 6. Grayburg Structure Map Over Lease Outline

This map, and many others were used to assist the operator in making the optimal intervention decision. A brief review of each of the interventions conducted in the field over the past three years can be found in the subsections below.

3.2.1 LOE Reductions

The operator experienced significant success in reducing routine lease operating expenses in this field during its first four years of ownership. The operator targeted four main areas of operating expenses: contract labor, surface equipment maintenance, chemical treatments, and workover rig expenses. The results in each of these categories can be found in the bullet points below.

- 70% reduction in contract labor from 2013 to 2015
- 40% reduction in surface equipment maintenance from 2013 to 2015
- 40% reduction in chemical treatment from 2013 to 2015
- 30% reduction in workover rig expenses from 2013 to 2015

Figure 7 also shows the percentage reduction in LOE from 2012 through 2016 as the operator achieved a 50% decrease in routine LOE over a four year period.

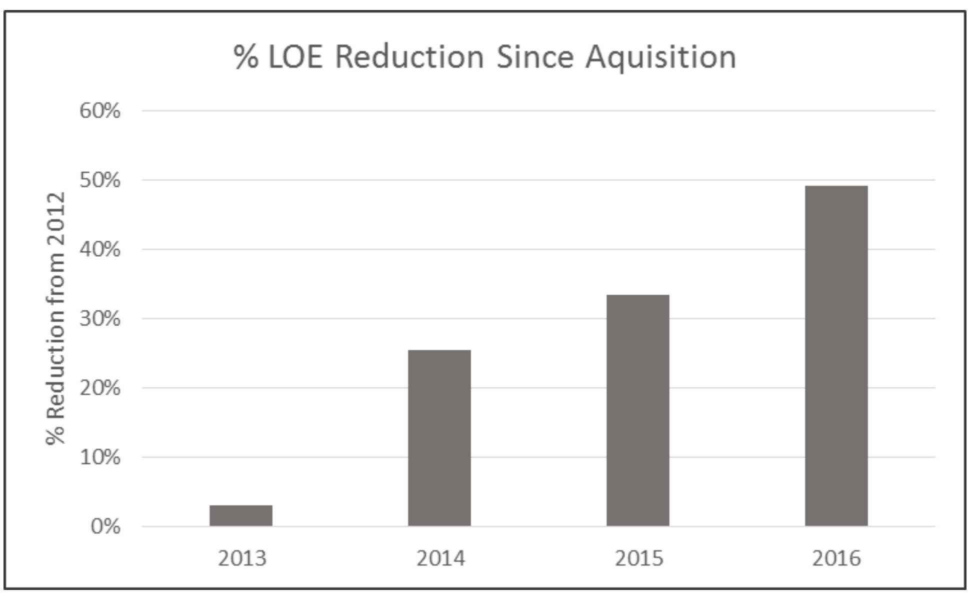


Figure 7. Percentage Reduction in LOE Since Acquisition

3.2.2 Reservoir Stimulation

As previously discussed, a review of the well files showed that implementing a second or third hydraulic fracture on a single wellbore, or “re-fracturing” wells had proven successful in the past. Thus the company decided to explore this option, along with what they had learned about the reservoir. Since the Grayburg had very low permeability and a high degree of heterogeneities, the company decided to employ a hydraulic fracture design that mimicked many of the designs used for unconventional wells. After a study was completed to select the optimal location in the reservoir as well as confirm wellbore integrity, the company began executing this new fracturing design in late 2015. A total of eight wells were fractured or re-fractured over a six month period and the results ranged from an initial production increase of 7 BOPD to over 100 BOPD. Due to a relatively low service cost to fracture these wells, all eight have proven economic and added reserves to the books of the operator. The results from these wells are used in the Green Tree model to calculate the risk adjusted value of continuing to re-fracture wells in this field.

3.2.3 Behind Pipe Potential

Many productive formations that are in the area of the S. Cowden field were evaluated by the engineering and geologic staff of the company to determine if any behind pipe potential existed in the wellbores. A review of the logs and reservoir properties, as well as a review of the well files cast doubt on the opportunity for behind pipe potential. Several pervious operators had perforated other zones with very little success. A review of well logs also showed the severe heterogeneities that exist in the field in the field, and discouraged the operations team from trying to complete a new formation. The only successful recompletion to date was in a wellbore that had been producing out of the Canyon, but due to low production the company plugged off the canyon and perforated and fractured the Grayburg. This well was one of the eight wells hydraulically fractured by the company with positive results. Opportunities to continue to convert Canyon wells into Grayburg wells still remain in the field and are under evaluation by the company. While no "new" formations exist to be tapped in existing wellbores, it is quite common for marginal well operators to perforate new zones in existing wellbores in order to grow reserves. Thus this section is important for the decision tree template to be a helpful tool to other marginal well operators.

3.2.4 Surface Equipment

Perhaps the simplest intervention, surface equipment upgrades can provide cost effective interventions that generate significant returns. The operator of the S. Cowden field watches fluid levels in wellbores very closely and makes adjustments to artificial lift in order to move the maximum amount of fluid possible out of each wellbore. Installing a larger pump is a relatively inexpensive intervention that has lead to meaningful increases in production with a payout of only a few months. Apart from adjustments in artificial lift, the operator has also installed a compressor to pull down the gas pressure in the annulus between the tubing and casing on several of the wells. These wells were often experiencing a pressure buildup in the annulus that was suppressing the reservoir's ability to flow fluids into the wellbore. Once the compressor was installed, the operator saw an immediate increase in production as the wells were producing a greater volume of fluid that resulted in more oil production. Many marginal well operators implement similar practices with surface equipment, and thus including this option in the model could prove helpful to other operators.

3.2.5 Infill Drilling

Infill drilling is often considered in legacy fields where an operator has found an unexploited area of the reservoir or has discovered a new productive horizon. Infill drilling is being considered in several areas of the S. Cowden field where the operator believes the Grayburg has not been penetrated. While no infill drilling has taken place to date, the current operator has created a plan for the infill drilling of four wells and has received bids from drilling contractors. The projected economics and production for infill drilling have been used in the model, as they are thought to be common for many other marginal well operators.

4. THE GREEN TREE MODEL

The following subsections will take a step by step walk through of the decision tree spreadsheet, or Green Tree, built to analyze marginal oil fields. A flow chart summarizing the first four steps can be found in Figure 8 below. All data used in the spreadsheet for this example came from the South Cowden field and represent best estimates for each possible input. The structure of the tree and the five interventions chosen reflect the intervention options previously discussed in section 3 in the South Cowden field, but also were chosen as likely options for any marginal oil field. The advantage of building this model in a spreadsheet without the use of visual basic programming is that all inputs and structures can be easily adjusted to fit needed variances or changes for other marginal oil fields.

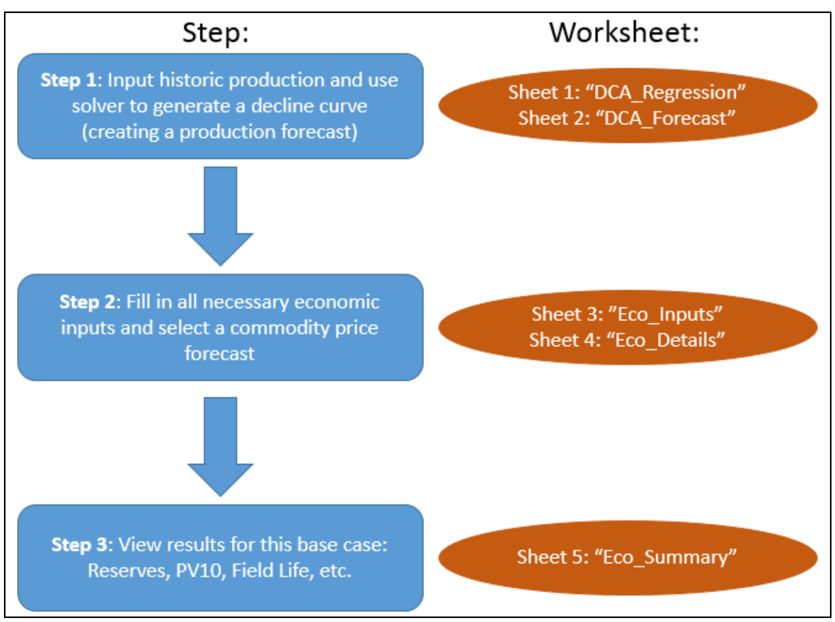


Figure 8. Flow Diagram for Green Tree Model, Part 1

4.1 Decline Curve Analysis

The first two sheets in the workbook calculate the existing reserves of the asset being evaluated in order to develop a base case NPV. The very first sheet, titled “1-DCA_Regression,” uses historical production from either a single well or a group of wells and fits a decline curve to the historical data by the least squares fitting method, with the aid of the solver function in excel. The user has the option to choose between using “Value Diff Squared” or “Percentage of Actual” for the residual type from a drop down list, as well as a choice for the objective function between “Monthly Residuals”, “Cum Residuals”, or “Both (Avg Monthly & Cum)”. Once these options have been selected and the user has input reasonable estimates for Qi, Di, and b, the user will use the solver function in excel to calculate the minimum value for the sum of the objective function column by altering the Qi, Di, and b (see Figure 9). Once the optimal Qi, Di, and b values have been selected by the solver, a monthly production rate will be calculated from the regression and plotted as a decline curve over the historical production data on a graph (see Figure 10). This cumulative production data for the field is also plotted on the right axis of this graph in Figure 10.

Decline Curve Analysis - Least Squares Fitting

**Only edit BLUE cells

				Qi	2121.8	vol/day			Objective Function Choice:		Monthly Residuals
				Di	0.095	/year (Nominal rate)					
				b	0.324						
							Residual Type:		Value Diff Squared		43,593,726,226
			Input Production Data		*Computed From Regression*				*Residuals*		
	Year	Month	Monthly	Cumulative	Q at t	Np	Monthly	Weight	Monthly	Cum	Objective Function
Jan-68	0.08	1	61,256	61,256	2,105.1	64,328	64,328	1.000	9,435,521	9,435,521	9,435,521
Feb-68	0.17	2	64,036	125,292	2,088.6	128,150	63,823	1.000	45,469	8,170,991	45,469
Mar-68	0.25	3	71,021	196,313	2,072.3	191,474	63,323	1.000	59,258,679	23,420,483	59,258,679
Apr-68	0.33	4	66,150	262,463	2,056.1	254,302	62,828	1.000	11,032,571	66,601,966	11,032,571
May-68	0.42	5	69,161	331,624	2,040.1	316,641	62,339	1.000	46,539,650	224,490,297	46,539,650
Jun-68	0.50	6	67,500	399,124	2,024.3	378,496	61,855	1.000	31,870,874	425,532,115	31,870,874
Jul-68	0.58	7	67,177	466,301	2,008.6	439,871	61,375	1.000	33,661,947	698,561,894	33,661,947
Aug-68	0.67	8	64,790	531,091	1,993.1	500,771	60,901	1.000	15,127,801	919,288,383	15,127,801
Sep-68	0.75	9	61,350	592,441	1,977.7	561,202	60,431	1.000	844,853	975,870,602	844,853
Oct-68	0.83	10	63,333	655,774	1,962.5	621,168	59,966	1.000	11,337,278	1,197,576,283	11,337,278
Nov-68	0.92	11	59,910	715,684	1,947.5	680,674	59,506	1.000	163,453	1,225,721,724	163,453
Dec-68	1.00	12	60,853	776,537	1,932.6	739,724	59,050	1.000	3,250,222	1,355,207,715	3,250,222
Jan-69	1.08	13	59,458	835,995	1,917.9	798,323	58,599	1.000	737,497	1,419,173,731	737,497
Feb-69	1.17	14	53,732	889,727	1,903.3	856,476	58,153	1.000	19,543,745	1,105,635,087	19,543,745
Mar-69	1.25	15	56,792	946,519	1,888.8	914,187	57,711	1.000	844,428	1,045,368,830	844,428
Apr-69	1.33	16	52,530	999,049	1,874.5	971,460	57,273	1.000	22,500,390	761,136,719	22,500,390
May-69	1.42	17	53,692	1,052,741	1,860.4	1,028,301	56,840	1.000	9,912,209	597,330,235	9,912,209
Jun-69	1.50	18	52,050	1,104,791	1,846.4	1,084,712	56,412	1.000	19,023,540	403,155,881	19,023,540
Jul-69	1.58	19	54,436	1,159,227	1,832.5	1,140,699	55,987	1.000	2,405,914	343,273,489	2,405,914
Aug-69	1.67	20	56,358	1,215,585	1,818.7	1,196,266	55,567	1.000	625,965	373,216,822	625,965
Sep-69	1.75	21	56,250	1,271,835	1,805.1	1,251,417	55,151	1.000	1,208,447	416,899,387	1,208,447
Oct-69	1.83	22	56,575	1,328,410	1,791.7	1,306,156	54,739	1.000	3,371,976	495,258,690	3,371,976
Nov-69	1.92	23	53,640	1,382,050	1,778.3	1,360,486	54,331	1.000	477,162	464,990,534	477,162
Dec-69	2.00	24	55,366	1,437,416	1,765.1	1,414,413	53,927	1.000	2,071,163	529,128,472	2,071,163

Figure 9. Layout for Decline Curve Analysis

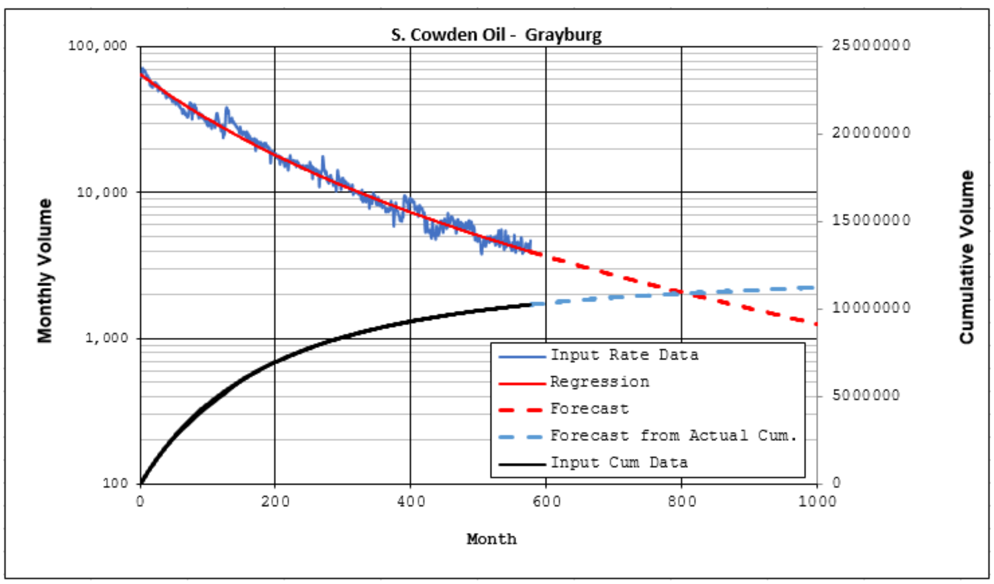


Figure 10. Decline Curve and Projections, S. Cowden Field

The Qi, Di, and b values calculated by the solver to create the decline curve automatically flow through to the second sheet in the workbook in order to forecast production, this second sheet is titled “2-DCA_Forecast”. These values are used to extend the decline curve on the same trajectory to forecast production for forty years into the future. The sheet gives the user the option to set a minimum decline rate either at the end of historical data or once the projected yearly decline rate drops below this value (see Figure 11). Forecasted production data also shows up as the dotted line on the graph in Figure 10 for monthly production and cumulative production.

DCA Forecast From Regression Fit											
**Only edit BLUE cells											
	Qi	2121.8	vol/day						Number of months of historic data:	576	
	Di	0.095	/year (nominal)							40 Year Forecast	
	b	0.324									
		Minimum Decline Rate:	0.030	/year (Nominal Rate)							
		Impose Tail Based On:	Hyperbolic Nominal Decline								
		EUR:	11,299,024				EUR:	11,295,341			11,313,344
	From DCA Equation				After Imposing Minimum Decline Rate						
Month (t)	q at t	Np	Monthly Volume	Nominal Decline /year	Imposed Nom. Decl. /year	b-value	q	DCA Monthly Volume	DCA Cumulative Volume	Adjusted Cumulative Volume	Adjusted Monthly Volume
0	2121.79	0	0.00		0.0948	0.32	2121.79	0	0	0	-
1	2105.11	64,328	64,328	0.095	0.0947	0.32	2105.11	64,328	64,328	61,256	**61,256**
2	2088.61	128,150	63,823	0.094	0.0944	0.32	2088.61	63,823	128,150	125,292	**64,036**
3	2072.28	191,474	63,323	0.094	0.0942	0.32	2072.28	63,323	191,474	196,313	**71,021**
4	2056.11	254,302	62,828	0.094	0.0940	0.32	2056.11	62,828	254,302	262,463	**66,150**
5	2040.11	316,641	62,339	0.094	0.0937	0.32	2040.11	62,339	316,641	331,624	**69,161**
6	2024.28	378,496	61,855	0.093	0.0935	0.32	2024.28	61,855	378,496	399,124	**67,500**
7	2008.61	439,871	61,375	0.093	0.0933	0.32	2008.61	61,375	439,871	466,301	**67,177**
8	1993.10	500,771	60,901	0.093	0.0930	0.32	1993.10	60,901	500,771	531,091	**64,790**
9	1977.74	561,202	60,431	0.093	0.0928	0.32	1977.74	60,431	561,202	592,441	**61,350**
10	1962.55	621,168	59,966	0.093	0.0926	0.32	1962.55	59,966	621,168	655,774	**63,333**
11	1947.50	680,674	59,506	0.092	0.0923	0.32	1947.50	59,506	680,674	715,684	**59,910**
12	1932.61	739,724	59,050	0.092	0.0921	0.32	1932.61	59,050	739,724	776,537	**60,853**
13	1917.87	798,323	58,599	0.092	0.0919	0.32	1917.87	58,599	798,323	835,995	**59,458**
14	1903.28	856,476	58,153	0.092	0.0916	0.32	1903.28	58,153	856,476	889,727	**53,732**
15	1888.84	914,187	57,711	0.091	0.0914	0.32	1888.84	57,711	914,187	946,519	**56,792**
16	1874.54	971,460	57,273	0.091	0.0912	0.32	1874.54	57,273	971,460	999,049	**52,530**
17	1860.38	1,028,301	56,840	0.091	0.0910	0.32	1860.38	56,840	1,028,301	1,052,741	**53,692**
18	1846.36	1,084,712	56,412	0.091	0.0908	0.32	1846.36	56,412	1,084,712	1,104,791	**52,050**
19	1832.49	1,140,699	55,987	0.091	0.0905	0.32	1832.49	55,987	1,140,699	1,159,227	**54,436**
20	1818.75	1,196,266	55,567	0.090	0.0903	0.32	1818.75	55,567	1,196,266	1,215,585	**56,358**
21	1805.14	1,251,417	55,151	0.090	0.0901	0.32	1805.14	55,151	1,251,417	1,271,835	**56,250**
22	1791.67	1,306,156	54,739	0.090	0.0899	0.32	1791.67	54,739	1,306,156	1,328,410	**56,575**

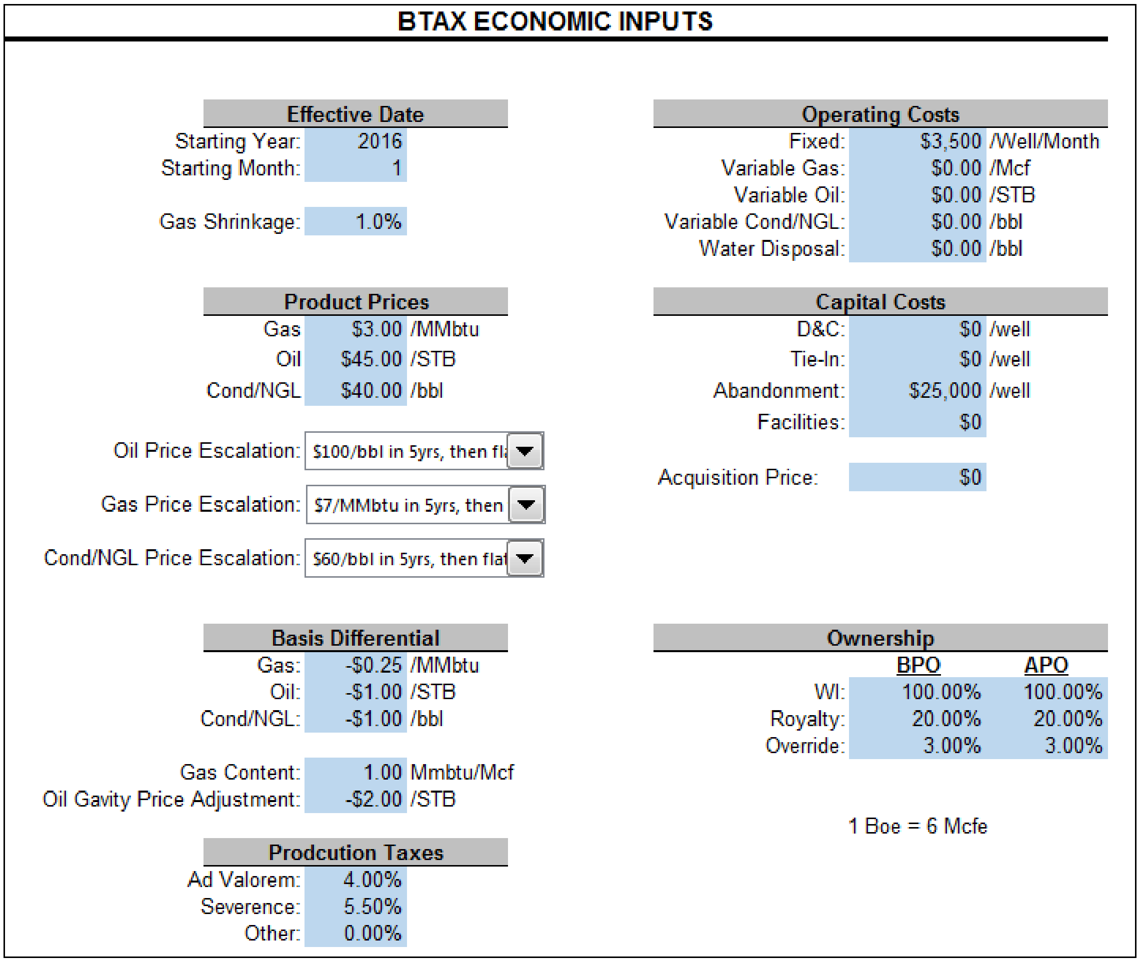
1-DCA_Regression | 2-DCA_Forecast | 3-Eco_Inputs | 4-Eco_Details | 5-Eco_Summary | 5.1-Eco_Summary2 | Decision Tree 3.0 | Tree Summ ...

Figure 11. DCA Forecast Sheet

As can be seen in Figure 9, it was determined that the optimal point to begin using historical data to build a decline curve for South Cowden was when production in the field peaked in 1968. Several challenges were faced when constructing this decline curve, which may or may not apply to other marginal fields applied to this model. First, very limited historical production was available for individual wells in this field as it was unitized for a waterflood in the 1950s and production has been reported on a unit basis since that time. Secondly, there was limited knowledge of historical interventions taken in the field before the current operator acquired the field in 2013, thus it was quite difficult to discern the causes for production spikes and drops. Lastly, the number of active wells reported in field over time was also unverified and appeared inaccurate at several points in time. Ideally, a decline curve would be built on a well by well basis in the field, the reserves of which could be amassed to determine field reserves or a general type curve could be developed for the field to be used in this model. Since neither of those options were possible with this field, the decline curve used monthly lease production for the field. To verify these results, the monthly lease production was divided by the total number of active wells in the field and a decline curve was created, which yielded very similar results to the monthly lease production used. Since the results were quite close, and the reported number of historically active wells in the field was suspect, the total monthly lease production was used for this analysis.

4.2 Eco Inputs/Price Scenarios/Valuation

The forty years of projected production data from the decline curve flow through to the fourth sheet in this workbook titled "4-Eco_Details". A sophisticated economic analysis, including a changing product price, operating expenses, capital expenses, taxes, ownership structure and payout arrangement, gas shrinkage, and basis differentials is applied to the forecasted monthly production in this sheet. Since the primary product produced in the S. Cowden field is oil, the decline curve built a forecast based off of historic oil production. Gas production rates in this field track nearly identically in line with oil production, so a simple ratio was calculated using historic production that was input into the Eco_Details sheet to create a gas production forecast. This Eco_Details sheet draws all of its economic inputs from the third sheet in the workbook, titled "3-Eco_Inputs" (see Figure 12). With this information, the Eco_Details sheet is able to calculate a plethora of economic information such as present value at various discount factors, internal rate of return, payout, field life, reserves, and much more which are summarized on the fifth tab "5-Eco_Summary" (see Figure 14).



BTAX ECONOMIC INPUTS

Effective Date		
Starting Year:	2016	
Starting Month:	1	
Gas Shrinkage:	1.0%	

Operating Costs		
Fixed:	$3,500	/Well/Month
Variable Gas:	$0.00	/Mcf
Variable Oil:	$0.00	/STB
Variable Cond/NGL:	$0.00	/bbl
Water Disposal:	$0.00	/bbl

Product Prices		
Gas	$3.00	/MMbtu
Oil	$45.00	/STB
Cond/NGL	$40.00	/bbl
Oil Price Escalation:	$100/bbl in 5yrs, then fl	
Gas Price Escalation:	$7/MMbtu in 5yrs, then	
Cond/NGL Price Escalation:	$60/bbl in 5yrs, then flat	

Capital Costs		
D&C:	$0	/well
Tie-In:	$0	/well
Abandonment:	$25,000	/well
Facilities:	$0	
Acquisition Price:	$0	

Basis Differential		
Gas:	-$0.25	/MMbtu
Oil:	-$1.00	/STB
Cond/NGL:	-$1.00	/bbl
Gas Content:	1.00	Mmbtu/Mcf
Oil Gavity Price Adjustment:	-$2.00	/STB

Ownership	BPO	APO
WI:	100.00%	100.00%
Royalty:	20.00%	20.00%
Override:	3.00%	3.00%

1 Boe = 6 Mcfe

Prodcution Taxes	
Ad Valorem:	4.00%
Severence:	5.50%
Other:	0.00%

Figure 12. Economic Inputs Page

All inputs seen in Figure 12 are best estimates used for the South Cowden field to calculate the base case PV10 value, from which all additions to NPV from field interventions are added. The economics sheet allows the user to input starting prices for oil, gas, and NGLs, and then select a target price for each commodity to reach within five years. Each commodity has a drop down list of three possible price targets from which to choose, but if the user would like to change these targets or add more options this can easily be done in excel. An oil price forecast reaching $100/bbl after five years and a gas price reaching $7/MMbtu after five years were used for the base case (see Figure 13). These values will be varied to create a sensitivity analysis later in section 5.

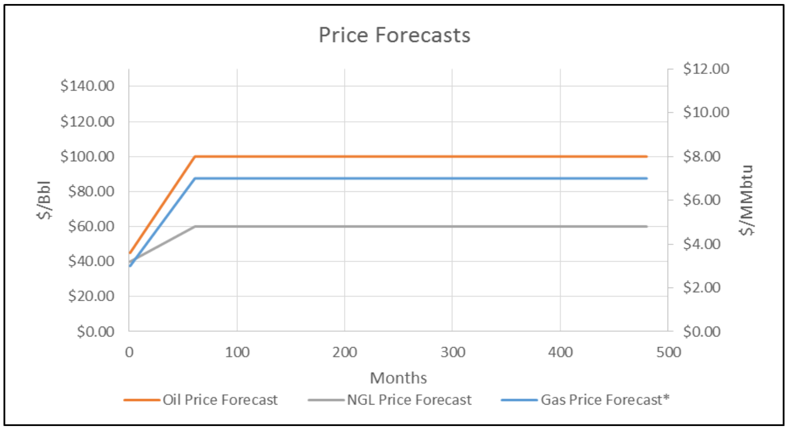


Figure 13. Model Price Forecasts

All inputs used in the Eco_Inputs sheet contribute to the calculations for each of the five interventions analyzed in this model. Each intervention has its own Eco_Details sheet which calculates the reserves and PV10 value by pulling its economic inputs and price scenarios from the Eco_Inputs sheet. Thus making a change to commodity price or any other economic input will automatically be applied to the economic projections for each intervention. A further explanation for each intervention can be found in the subsections of 4.3 in this report.

RESERVES AND ECONOMICS

AS OF SEPTEMBER 1, 2016

Ref: S. Cowden Grayburg PDP, Ector County, Texas — Proved Devloped, Undisclosed Company

		Gross Production		Net Production		Product Prices		Expenditure				Operating Revenue			Cum. NCF
		Oil	Gas	Oil	Gas	Oil	Gas	Capital	LOE	Taxes	TOTAL	Gross	Net	Cum. NCF	Disc. @10%
Year	Months	(Stb)	(MScf)	(Stb)	(MScf)	($/Stb)	($/MScf)	($)	($)	($)	($)	($)	($)	($)	($)
2016	12	46,336	12,194	35,679	9,295	46.65	3.09	-	1,680,000	210,493	1,890,493	2,215,713	1,706,099	(135,981)	1,626,701
2017	12	44,614	11,740	34,352	8,950	58.04	3.92	-	1,680,000	250,174	1,930,174	2,633,413	2,027,728	155,094	1,757,602
2018	12	42,975	11,309	33,091	8,621	69.04	4.72	-	1,680,000	286,746	1,966,746	3,018,380	2,324,152	423,358	1,831,399
2019	12	41,415	10,899	31,889	8,308	80.04	5.52	-	1,680,000	320,437	2,000,437	3,373,021	2,597,226	670,490	1,860,525
2020	12	39,929	10,508	30,745	8,010	91.04	6.32	-	1,680,000	351,458	2,031,458	3,699,554	2,848,657	898,034	1,855,124
2021	12	38,513	10,135	29,655	7,726	97.00	6.75	-	1,680,000	361,324	2,041,324	3,803,411	2,928,626	970,407	1,733,821
2022	12	37,162	9,780	28,615	7,455	97.00	6.75	-	1,680,000	348,654	2,028,654	3,670,038	2,825,929	877,466	1,520,929
2023	12	35,874	9,440	27,623	7,196	97.00	6.75	-	1,680,000	336,565	2,016,565	3,542,789	2,727,948	788,793	1,334,722
2024	12	34,644	9,117	26,676	6,950	97.00	6.75	-	1,680,000	325,025	2,005,025	3,421,315	2,634,413	704,143	1,171,780
2025	12	33,469	8,808	25,771	6,714	97.00	6.75	-	1,680,000	314,003	1,994,003	3,305,293	2,545,076	623,293	1,029,130
2026	12	32,346	8,512	24,907	6,489	97.00	6.75	-	1,680,000	303,470	1,983,470	3,194,421	2,459,705	546,033	904,190
2027	12	31,273	8,230	24,080	6,273	97.00	6.75	-	1,680,000	293,400	1,973,400	3,088,419	2,378,083	472,165	794,714
2028	12	30,246	7,960	23,289	6,068	97.00	6.75	-	1,680,000	283,767	1,963,767	2,987,023	2,300,008	401,507	698,748
2029	12	29,264	7,701	22,533	5,870	97.00	6.75	-	1,680,000	274,549	1,954,549	2,889,986	2,225,290	333,887	614,590
2030	12	28,323	7,453	21,809	5,682	97.00	6.75	-	1,680,000	265,722	1,945,722	2,797,078	2,153,750	269,144	540,756
Rem	38	83,920	22,084	64,618	16,835	97.00	6.75	-	5,320,000	787,332	6,107,332	8,287,701	6,381,530	455,285	1,456,593
Total		630,301	165,869	485,331	126,442			0	30,520,000	5,313,118	35,833,118	55,927,556	43,064,218		

						NPV Profile	
Initial WI Fraction	1.000	LOE ($/Well/Mo.)	3,500	Net Present Value @ 10% ($)	3,834,856	Percent	NPV ($)
Final WI Fraction	1.000	Production Start Date	1/1/2016	Rate of Return (ROR)	1.045	0%	7,453,118
		Severance Tax (Percent)	5.50%			5%	5,320,273
Initial Net Oil Fraction	0.770	Advalorem Tax (Percent)	4.00%	Payout (Disc. @ 10%), Months	480	10%	3,834,856
Initial Net Gas Fraction	0.770	BBL to MCF	3.8	Economic Life, Years	18.25	15%	2,802,092
Final Net Oil Fraction	0.770			F&D, $/BOE	0.00	20%	2,077,531
Final Net Gas Fraction	0.770	Reserves (BOE)	506,405	F&D, $/Mcfe	0.00	25%	1,561,866
		Reserves (Mcfe)	3,038,430				

*Source Mian vol. 1 ch. 3

Figure 14. Eco. Summary for Base Case Reserves

4.3 Interventions

Five intervention options are provided in this model based off what was used in the South Cowden field. While these five interventions will prove applicable for many marginal oil fields, the user has the ability to edit, add, or subtract from this list with relatively little effort in excel. In the sub-sections below the inputs and set-up for each intervention in the model are explained. A flow diagram showing a step by step process for determining the optimal intervention in the model can be found below in Figure 15.

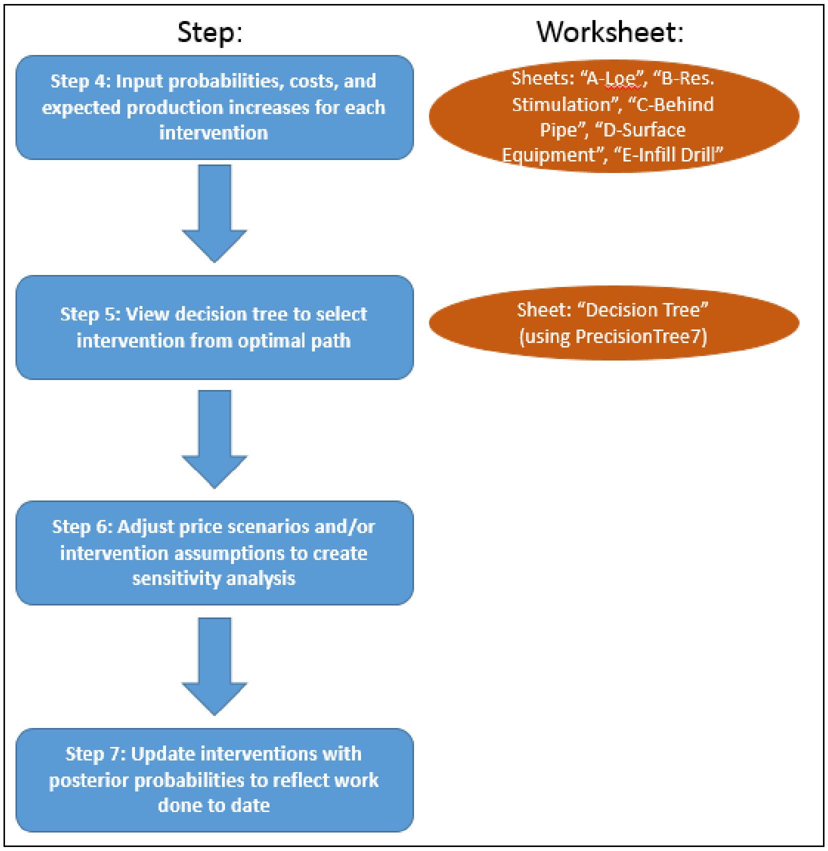


Figure 15. Flow Diagram for Green Tree Model, Part 2

4.3.1 LOE Reduction

The first sheet after the decision tree is titled "A-LOE," which is the location for all LOE related probabilities and forecasts that feed into the decision tree (see Figure 16).

LOE Reductions Summary

***Edit cells in BLUE only

Historical LOE Reductions		
Field Name	% LOE Reduction After 5 Years	Category
Field 1	30%	Large
Field 2	20%	Small
Field 3	60%	Large
Field 4	30%	Large
Field 5	40%	Large
Field 6	20%	Small
Field 7	0%	No
	% Large	57.14%
	% Small	28.57%
	% No	14.29%

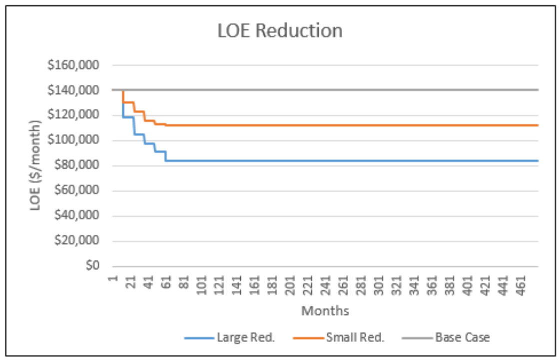
*Large is greater than or equal to 30%
*Small is greater than 0% and less than 30%
*No is equal to 0%

Large PV10	$8,089,503
Small PV10	$5,988,109
Base PV10	$3,834,856

Year	Large (40% Reduction)	Small (20% Reduction)
0	0.0%	0
1	15.0%	7.0%
2	10.0%	5.0%
3	5.0%	5.0%
4	5.0%	2.0%
5	5.0%	1.0%
Total	40.0%	20.0%

*reductions over 5 years

Year	Large LOE Forecast $/Well/Month	Small LOE Forecast $/Well/Month
2016	3500	3500
2017	2975	3255
2018	2625	3080
2019	2450	2905
2020	2275	2835
2021	2100	2800
Rem.	2100	2800



... Decision Tree 3.0 | Tree Summary | A-LOE | B-Res. Stimulation | C-Behind Pipe | D-Surface Equipment | E-Infill Drilling | Appendi

Figure 16. LOE Reduction Input Sheet

All cells highlighted in blue should be adjusted by the user to match expected results for the field being analyzed. The first box on the left, titled “Historical LOE Reductions”, is set up for the user to input LOE reduction results from previous fields. Once these values are placed in the sheet, it automatically transfers the percentage of “large”, “small”, and “no” LOE reductions to the decision tree. Next, the user inputs expected values for a large and a small LOE reduction over five years. The user will base this information after past results in similar fields and will be able to view the changes in monthly LOE in the table to the far right as well as the graph placed below the tables. Both the large and small percent reductions are applied to copies of the

Eco_Details sheet which pulls its inputs from the Eco_Inputs sheet. This way, a PV10 value can be calculated for both the large and small LOE reductions that can be directly compared to the base case PV10 since all other inputs are identical. The increase in PV10 from both large and small LOE reductions can be seen on this sheet and are directly tied into the decision tree. A snapshot of this part of the tree can be seen below in Figure 17.

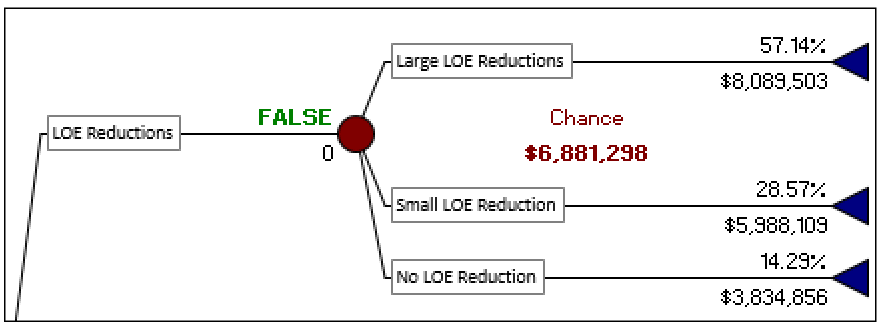


Figure 17. LOE Reductions Branch of Decision Tree

4.3.2 Reservoir Stimulation

The second intervention addressed in the model is reservoir stimulation, which in this case focuses on hydraulic fracturing or acidizing selected wellbores. Similar to the LOE reductions sheet, this sheet calculates probabilities based on the historical results of the operator in similar fields. Each of these calculated probabilities (highlighted in bold font) are tied directly into the decision tree (see Figure 18).

Reservior Stimulation Summary

***Edit cells in BLUE only

Historical Success of Stimulation in Marginal Fields	
Field 1	0%
Field 2	90%
Field 3	65%
Field 4	75%
Field 5	55%
Field 6	85%
Field 7	0%
Promising Res. Study	**53%**
Uncompatible with Res.	**47%**

Frac

Historical Chance of Wellbore Candidates	
Field 1	100%
Field 2	0%
Field 3	100%
Field 4	100%
Field 5	100%
Field 6	100%
Field 7	100%
Wellbore Candidates	**86%**
No Wellbore Candidates	**14%**

Historical Frac Results	
Field 1	Match
Field 2	Outperform
Field 3	Outperform
Field 4	Outperform
Field 5	Underperform
Field 6	Match
Outperform Projections	**50.00%**
Match Projections	**33.33%**
Underperform Projections	**16.67%**

Acidize

Historical Chance of Wellbore Candidates	
Field 1	100%
Field 2	0%
Field 3	100%
Field 4	100%
Field 5	100%
Field 6	100%
Field 7	100%
Wellbore Candidates	**86%**
No Wellbore Candidates	**14%**

Historical Acidize Results	
Field 1	Match
Field 2	Match
Field 3	Outperform
Field 4	Outperform
Field 5	Underperform
Field 6	Match
Outperform Projections	**33.33%**
Match Projections	**50.00%**
Underperform Projections	**16.67%**

Figure 18. Reservoir Stimulation Probability Inputs

Next, the user inputs the estimated cost of a hydraulic fracture job for a single well or an acid stimulation for a single well (see Figure 19). Estimated production increases per well as a result of the stimulation must also be estimated by the user, accompanied by alternative projections for cases if the wells underperform or outperform the provided projections. Lastly, the user must estimate how many wells per year are stimulated under each possible scenario. This will vary greatly based off the total number of well in the field, the amount of capital the company is willing to spend on stimulation, and the risk tolerance of the company among other factors. A PV10 for each type of stimulation as well as each possible outcome is then calculated based off of these inputs. The capital costs and production increases (or decreases) are applied to a copy of the Eco_Details sheet, so that all other inputs will match the base case apart from the effect of the stimulation. The PV10 results (highlighted in bold font) for each case and scenario are tied directly into the decision tree and used by the tree to calculate the EMV.

S. Cowden Field	
Frac Cost:	$125,000
Outperform NPV:	**$21,469,438**
Match NPV:	**$10,548,797**
Underperform NPV:	**$3,615,193**

S. Cowden Field	
Acid Cost:	$50,000
Outperform NPV:	**$10,356,655**
Match NPV:	**$6,410,575**
Underperform NPV:	**$4,042,696**

Frac - Match Projections

Years	# Wells (cum)	BPD Inc./Well*
0	0	0
1	6	10
2	12	7
3	18	6
4	20	5
5	20	3

*Avg. per year

Acid - Match Projections

Years	# Wells (cum)	BPD Inc./Well*
0	0	0
1	6	4
2	12	3
3	18	2
4	20	2
5	20	1

*Avg. per year

Frac - Outperform Projections

Years	# Wells (cum)	BPD Inc./Well*
0	0	0
1	6	30
2	18	15
3	20	12
4	20	8
5	20	5

*Avg. per year

Acid - Outperform Projections

Years	# Wells (cum)	BPD Inc./Well*
0	0	0
1	6	8
2	18	6
3	20	5
4	20	4
5	20	3

*Avg. per year

Frac - Underperform Projections

Years	# Wells (cum)	BPD Inc./Well*
0	0	0
1	6	3
2	8	2
3	8	1
4	8	0
5	8	0

*Avg. per year

Acid - Underperform Projections

Years	# Wells (cum)	BPD Inc./Well*
0	0	0
1	6	2
2	8	1
3	8	1
4	8	1
5	8	0

*Avg. per year

Figure 19. Reservoir Stimulation Price and Production Projections

Figure 20 shows the production changes for both the fracture and acidize scenarios for all three of the possible outcomes, plus the base case production if no interventions are completed. The model is designed to increase production for each intervention on a yearly basis for a period of five years; this is why each of the production increases in Figure 20 appears to increase in set increments and not in a smooth fashion. While actual production changes would occur on a monthly basis, the resulting economics from monthly over yearly are not significant, thus the simplified yearly approach was used in this model.

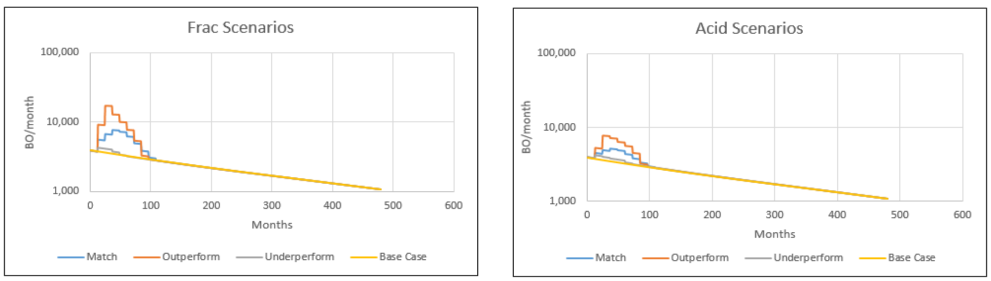


Figure 20. Graphs of Production for Reservoir Stimulation Scenarios

Each of the inputted values and probabilities used for fracturing and acidizing flows through to the decision tree tab on the spreadsheet, calculating an EMV for each possible outcome. A screenshot of the reservoir stimulation branch of the decision tree and its accompanying EMVs can be found in Figure 21 below. The decision tree holds a branch for each of the five inputs, directing the user towards the branch with the highest intervention EMV.

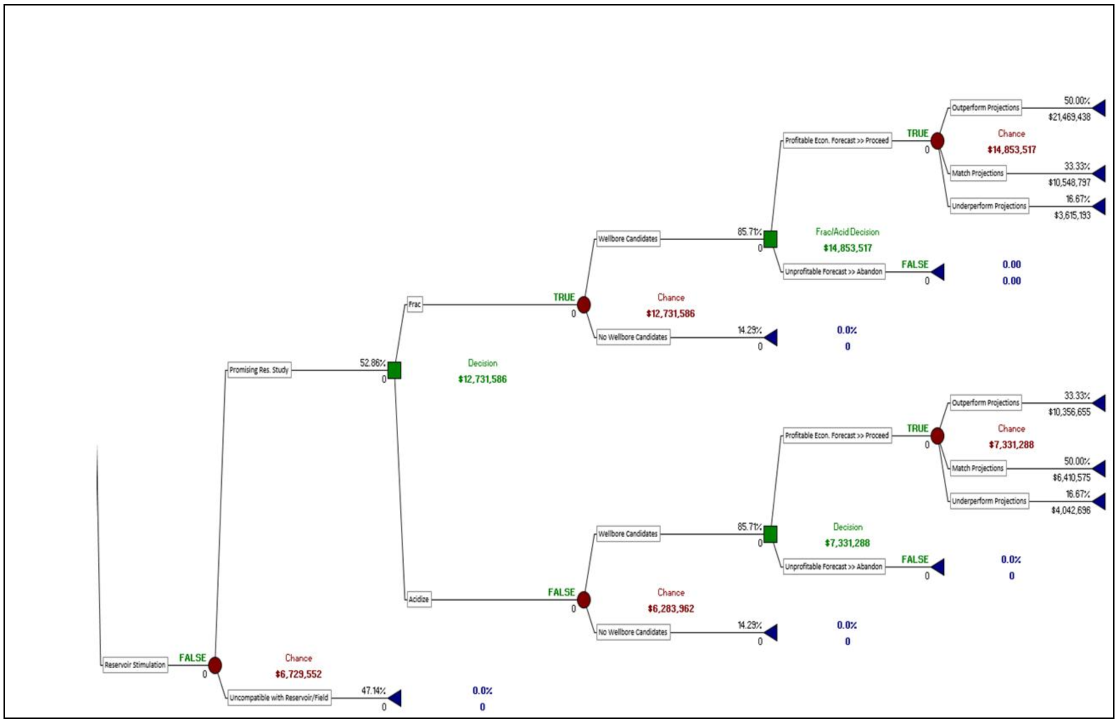


Figure 21. Reservoir Stimulation Decision Tree Branch

4.3.3 Behind Pipe

Behind pipe potential for the S. Cowden field involves perforating a previously unproduced zone in an existing wellbore with the option to stimulate via hydraulic fracture after the perforation is complete. The organization and structure of this sheet is nearly identical to the previous sheet for reservoir stimulation, and all calculated values (highlighted in bold) flow to the decision tree. The first table, "Historical Success of Behind Pipe Potential in Marginal Fields", allows the user to track previous success with behind pipe potential to determine the likelihood of having success in the field under evaluation (see Figure 22). Next, the chance of having wellbores suitable for perforation is calculated as well as the outcomes of past results as can be seen in Figure 22.

Behind Pipe Summary

***Edit cells in BLUE only

Historical Success of Behind Pipe Potential in Marginal Fields	
Field 1	0%
Field 2	0%
Field 3	100%
Field 4	0%
Field 5	0%
Field 6	100%
Field 7	0%
Promising Res. Study	**29%**
Uncompatible with Res.	**71%**

Perforate New Zone	
Historical Chance of Wellbore Candidates	
Field 1	100%
Field 2	0%
Field 3	100%
Field 4	100%
Field 5	100%
Field 6	100%
Field 7	100%
Wellbore Candidates	**86%**
No Wellbore Candidates	**14%**

Perforate & Stimulate New Zone	
Historical Chance of Wellbore Candidates	
Field 1	100%
Field 2	100%
Field 3	100%
Field 4	100%
Field 5	100%
Field 6	0%
Field 7	100%
Wellbore Candidates	**86%**
No Wellbore Candidates	**14%**

Historical Perf Results	
Field 1	Match
Field 2	Outperform
Field 3	Outperform
Field 4	Outperform
Field 5	Underperform
Field 6	Underperform
Outperform Projections	**50.00%**
Match Projections	**16.67%**
Underperform Projections	**33.33%**

Historical Perf & Stim Results	
Field 1	Match
Field 2	Match
Field 3	Outperform
Field 4	Outperform
Field 5	Underperform
Field 6	Underperform
Outperform Projections	**33.33%**
Match Projections	**33.33%**
Underperform Projections	**33.33%**

Figure 22. Behind Pipe Probability Inputs

These input boxes are followed by cost inputs, and estimates for each of the future production outcomes (match, outperform, underperform) and their associated well count (see Figure 23). This sheet is set up with the same structure and flows to the decision tree in the same way as the previously discussed intervention of reservoir stimulation.

S. Cowden Field	
Perf Cost:	$40,000
Outperform NPV:	**$11,994,440**
Match NPV:	**$7,886,450**
Underperform NPV:	**$4,471,909**

S. Cowden Field	
Perf and Stim Cost:	$150,000
Outperform NPV:	**$14,488,904**
Match NPV:	**$8,839,873**
Underperform NPV:	**$4,332,711**

Perf - Match Projections

Years	# Wells (cum)	BPD Inc./Well*
0	0	0
1	3	10
2	6	7
3	10	6
4	10	5
5	10	3

*Avg. per year

Perf & Stim - Match Projections

Years	# Wells (cum)	BPD Inc./Well*
0	0	0
1	3	15
2	6	12
3	10	8
4	10	5
5	10	4

*Avg. per year

Perf - Outperform Projections

Years	# Wells (cum)	BPD Inc./Well*
0	0	0
1	3	20
2	8	15
3	10	12
4	10	8
5	10	5

*Avg. per year

Perf & Stim - Outperform Projections

Years	# Wells (cum)	BPD Inc./Well*
0	0	0
1	3	30
2	8	24
3	10	15
4	10	10
5	10	5

*Avg. per year

Perf - Underperform Projections

Years	# Wells (cum)	BPD Inc./Well*
0	0	0
1	3	4
2	6	3
3	6	2
4	6	1
5	6	0

*Avg. per year

Perf & Stim - Underperform Projections

Years	# Wells (cum)	BPD Inc./Well*
0	0	0
1	3	5
2	6	4
3	6	3
4	6	2
5	6	1

*Avg. per year

Figure 23. Behind Pipe Costs and Production Projections

This sheet also populates a graph that shows the effect on monthly oil production during the five year period the intervention is implement. Each of the outputs for match, outperform, and underperform, can be compared to the base case production curve for each of the behind pipe scenarios (see Figure 24).

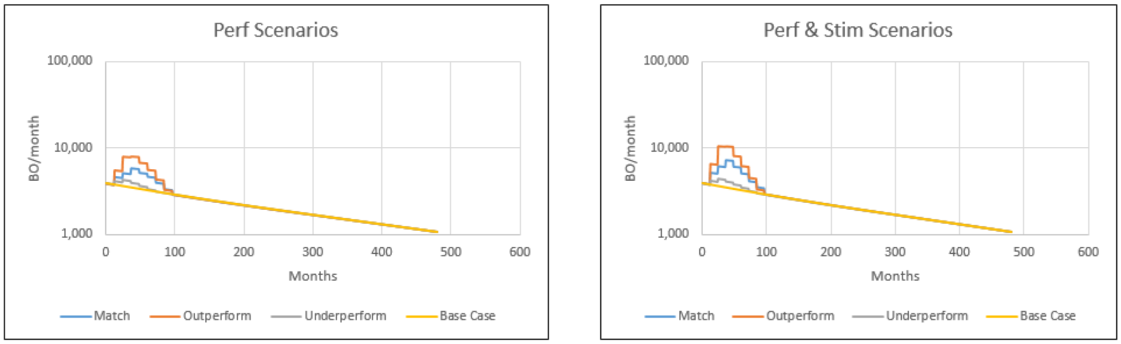


Figure 24. Graphs of Production for Behind Pipe Interventions

4.3.4 Surface Equipment

The inputs page for surface equipment contains five possible intervention options: upgrade pump type, upgrade pump size, speed up/lengthen stroke, add wellhead compression, or add backside compression. The first three options fall under the category of "Artificial Lift Upgrades", and the latter two are considered "Compression Upgrades". While this model calculates the optimal path by selecting only one intervention at a time, it is possible for an operator to implement many of these interventions simultaneously. The organization of this sheet follows the structure of the previously discussed interventions, as probabilities for each possible outcome are first calculated from the operator's historical results, then inputs for cost, production projections, and well counts are inserted. All probabilities and PV10 values calculated in the sheet and highlighted in bold font flow directly into the decision tree.

Because three main intervention options exist for artificial lift upgrades and two options exist for compression upgrades, the inputs were split into two different sections on the same sheet.

Surface Equipment Summary

***Edit cells in BLUE only

	Historical Success of Surface Eq. Upgrade in Marginal Fields	Artificial Lift Upgrades: Upgrade Pump Type — Historical Chance of Wellbore Candidates	Artificial Lift Upgrades: Upgrade Pump Size — Historical Chance of Wellbore Candidates	Artificial Lift Upgrades: Speed Up/Lengthen Stroke — Historical Chance of Wellbore Candidates
Field 1	100%	0%	100%	0%
Field 2	100%	0%	100%	100%
Field 3	100%	100%	100%	0%
Field 4	100%	0%	100%	100%
Field 5	100%	0%	0%	0%
Field 6	100%	100%	100%	100%
Field 7	0%	100%	100%	100%

Promising Potential	86%
No Upgrade Potential	14%

	Upgrade Pump Type	Upgrade Pump Size	Speed Up/Lengthen Stroke
Wellbore Candidates	43%	86%	57%
No Wellbore Candidates	57%	14%	43%

	Historical Chance of Surface Eq. Compatible for Inc. Volumes
Field 1	100%
Field 2	100%
Field 3	100%
Field 4	100%
Field 5	100%
Field 6	100%
Field 7	100%
Wellbore Candidates	100%
No Wellbore Candidates	0%

	Historical Pump Type Results	Historical Pump Size Results	Historical Stroke Results
Field 1	Match	Match	Match
Field 2	Match	Outperform	Outperform
Field 3	Outperform	Outperform	Outperform
Field 4	Outperform	Match	Outperform
Field 5	Underperform	Match	Match
Field 6	Match	Underperform	Underperform
Outperform Projections	**33.33%**	**33.33%**	**50.00%**
Match Projections	**50.00%**	**50.00%**	**33.33%**
Underperform Projections	**16.67%**	**16.67%**	**16.67%**

Figure 25. Surface Equipment Probabilities, Artificial Lift

The left half of the sheet addresses the probabilities of success for surface equipment and the probabilities of success for artificial lift upgrades (see Figure 25). Directly below these probabilities calculations are the inputs for prices and production increases for each of three types of artificial lift upgrades (see Figure 26). As a reminder to the reader, all cells highlighted blue are inputs for the user, while all numbers in bold are the calculations that flow through to the decision tree.

S. Cowden Field	
Pump Cost:	$30,000
Outperform NPV	**$15,171,427**
Match NPV	**$8,769,879**
Underperform NPV	**$4,646,393**

S. Cowden Field	
Pump Cost:	$10,000
Outperform NPV	**$11,653,976**
Match NPV	**$7,429,910**
Underperform NPV	**$4,763,727**

S. Cowden Field	
Procedure Cost:	$5,000
Outperform NPV	**$10,719,349**
Match NPV	**$7,308,523**
Underperform NPV	**$4,793,061**

Pump Type - Match Projections

Years	# Wells (cum)	BPD Inc./Well*
0	0	0
1	3	10
2	6	7
3	10	6
4	12	5
5	12	3

*Avg. per year

Pump Size - Match Projections

Years	# Wells (cum)	BPD Inc./Well*
0	0	0
1	3	7
2	6	5
3	10	4
4	12	3
5	12	3

*Avg. per year

SL/Speed - Match Projections

Years	# Wells (cum)	BPD Inc./Well*
0	0	0
1	3	6
2	6	5
3	10	4
4	12	3
5	12	3

*Avg. per year

Pump Type - Outperform Projections

Years	# Wells (cum)	BPD Inc./Well*
0	0	0
1	3	20
2	8	15
3	10	12
4	12	8
5	14	5

*Avg. per year

Pump Size - Outperform Projections

Years	# Wells (cum)	BPD Inc./Well*
0	0	0
1	3	12
2	8	10
3	10	8
4	12	6
5	14	5

*Avg. per year

SL/Speed - Outperform Projections

Years	# Wells (cum)	BPD Inc./Well*
0	0	0
1	3	10
2	8	8
3	10	7
4	12	6
5	14	5

*Avg. per year

Pump Type - Underperform Projections

Years	# Wells (cum)	BPD Inc./Well*
0	0	0
1	3	4
2	6	3
3	7	2
4	7	1
5	7	0

*Avg. per year

Pump Size - Underperform Projections

Years	# Wells (cum)	BPD Inc./Well*
0	0	0
1	3	4
2	6	3
3	7	2
4	7	1
5	7	0

*Avg. per year

SL/Speed - Underperform Projections

Years	# Wells (cum)	BPD Inc./Well*
0	0	0
1	3	4
2	6	3
3	7	2
4	7	1
5	7	0

*Avg. per year

Figure 26. Surface Equipment Price and Production Projections, Artificial Lift

This sheet also has graphs that update in real time to show the expected production increases for each type of artificial lift upgrade and each possible outcome within each type (see Figure 27).

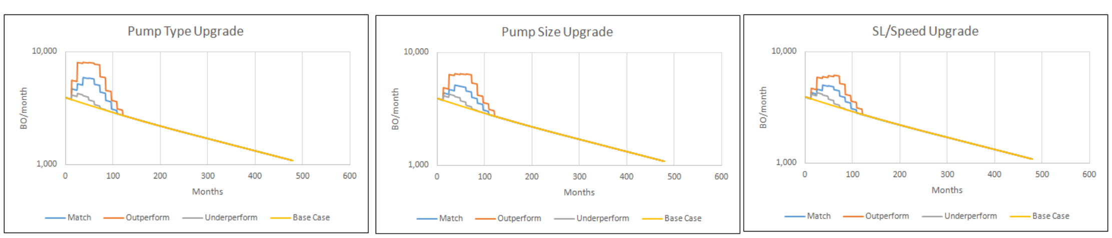


Figure 27. Surface Equipment Production Graphs, Artificial Lift

The right part of the sheet contains the input cells for compression upgrades. The top half, Figure 28, shows the input cells for probability calculations for compression.

Surface Equipment Upgrades

Compression Upgrades

Add Compression

Historical Chance of Wellbore Candidates	
Field 1	0%
Field 2	0%
Field 3	100%
Field 4	0%
Field 5	0%
Field 6	100%
Field 7	100%
Wellbore Candidates	**43%**
No Wellbore Candidates	**57%**

Historical Wellhead Compression Results	
Field 1	Match
Field 2	Match
Field 3	Outperform
Field 4	Outperform
Field 5	Underperform
Field 6	Underperform
Outperform Projections	**33.33%**
Match Projections	**33.33%**
Underperform Projections	**33.33%**

Historical Back Side Compression Results	
Field 1	Match
Field 2	Match
Field 3	Outperform
Field 4	Match
Field 5	Match
Field 6	Underperform
Outperform Projections	**16.67%**
Match Projections	**66.67%**
Underperform Projections	**16.67%**

Figure 28. Surface Equipment Probabilities, Compression

The bottom half of the sheet, Figure 29, shows the price and projected production increases for each type of compression. This is followed by Figure 30, which graphically shows the production changes for each outcome of each type of productio upgrades.

S. Cowden Field	
Compressor Cost:*	$10,000
Outperform NPV	**$8,835,349**
Match NPV	**$5,878,526**
Underperform NPV	**$3,776,189**

*per well

WH Compression - Match Projections		
Years	# Wells (cum)	BPD Inc./Well*
0	0	0
1	3	5
2	6	4
3	10	3
4	10	2
5	10	1

*Avg. per year

WH Compression - Outperform Projections		
Years	# Wells (cum)	BPD Inc./Well*
0	0	0
1	3	10
2	8	8
3	10	7
4	10	6
5	10	5

*Avg. per year

WH Compression - Underperform Projections		
Years	# Wells (cum)	BPD Inc./Well*
0	0	0
1	3	0
2	6	0
3	7	0
4	7	0
5	7	0

*Avg. per year

S. Cowden Field	
Compressor Cost:*	$8,000
Outperform NPV	**$6,317,882**
Match NPV	**$5,403,277**
Underperform NPV	**$3,787,922**

*per well

BS Compression - Match Projections		
Years	# Wells (cum)	BPD Inc./Well*
0	0	0
1	3	3
2	6	3
3	10	2
4	10	2
5	10	1

*Avg. per year

BS Compression - Outperform Projections		
Years	# Wells (cum)	BPD Inc./Well*
0	0	0
1	3	5
2	8	4
3	10	4
4	10	3
5	10	2

*Avg. per year

BS Compression - Underperform Projections		
Years	# Wells (cum)	BPD Inc./Well*
0	0	0
1	3	0
2	6	0
3	7	0
4	7	0
5	7	0

*Avg. per year

Figure 29. Surface Equipment Costs and Production Projections, Compression

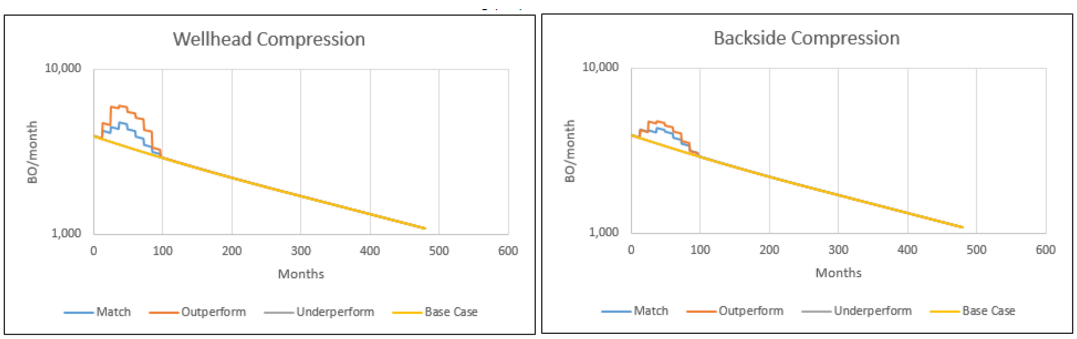


Figure 30. Surface Equipment Production Graphs, Compression

Lastly, screenshots of the decision tree branches for both types of surface equipment upgrades can be in Figure 31 and Figure 32 below. There is one branch for the surface equipment intervention that is split into two parts, artificial lift (Figure 31) and compression (Figure 32).

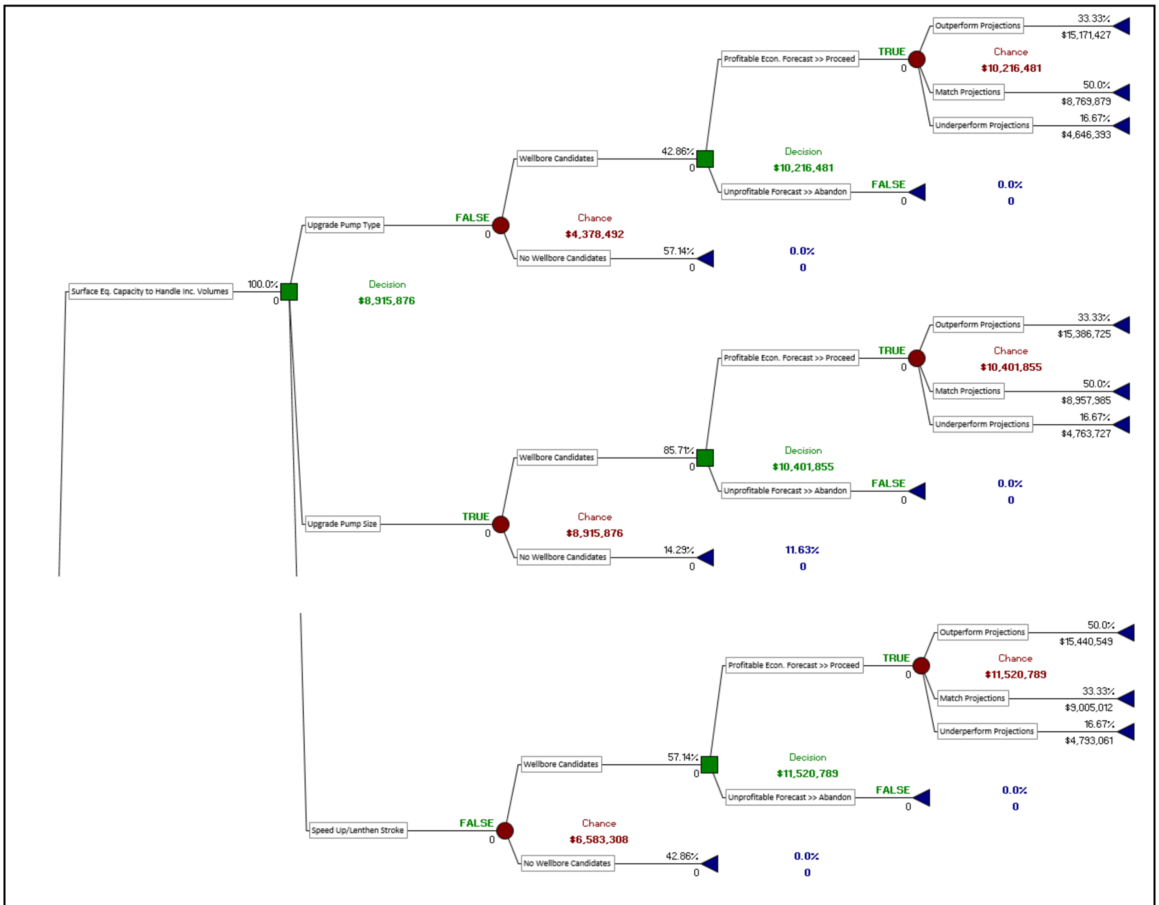


Figure 31. Surface Equipment Decision Tree, Artificial Lift

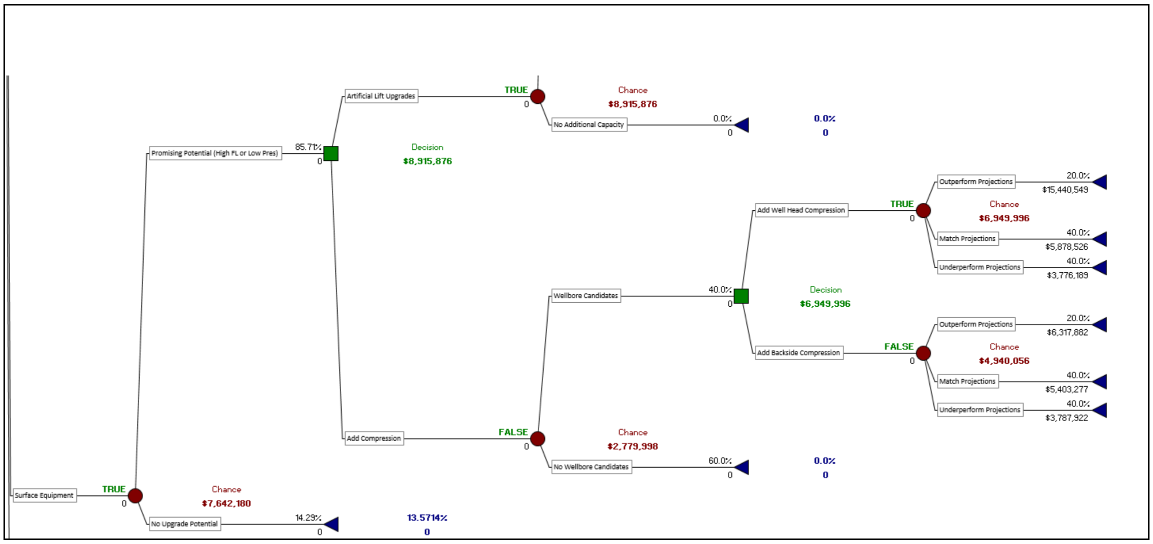


Figure 32. Surface Equipment Decision Tree, Compression

4.3.5 Infill Drilling

The fifth intervention covered in this model is the prospect for infill drilling in a marginal oil field. While this prospect might be the least likely intervention in a marginal oil field as it has the highest capital cost and it is likely that an infill drilling campaign has already been conducted in a legacy field, it also has the potential to provide the largest production increase. Historic success from similar fields is used as an input to calculate the probability of success in the field under study. Then costs, production projections, and well counts are selected by the user for the spreadsheet to calculate the PV10 of each possible infill drilling outcome (match projections, outperform projections, underperform projections, or dry hole) in a similar manner to the previous four interventions. The top of the sheet covers the probability inputs for the historic success of infill drilling in marginal fields as well as the chances for wellbore candidates and results from past fields (see Figure 33).

Infill Drilling Summary

***Edit cells in BLUE only

Infill Drilling

Historical Success of Infill Drilling in Marginal Fields	
Field 1	0%
Field 2	100%
Field 3	0%
Field 4	100%
Field 5	0%
Field 6	0%
Field 7	0%
Promising Res. Study	**29%**
Uncompatible with Res.	**71%**

Historical Chance of Wellbore Candidates	
Field 1	100%
Field 2	0%
Field 3	100%
Field 4	0%
Field 5	0%
Field 6	100%
Field 7	100%
Wellbore Candidates	**57%**
No Wellbore Candidates	**43%**

Historical Infill Results	
Field 1	Dry
Field 2	Match
Field 3	Outperform
Field 4	Outperform
Field 5	Underperform
Field 6	Match
Outperform Projections	**33.33%**
Match Projections	**33.33%**
Underperform Projections	**16.67%**
Dry Hole Projections	**16.67%**

Figure 33. Infill Drilling Probabilities

Below the probabilities are the cost and production projections for each of the possible outcomes of infill drilling (see Figure 34). All cells highlighted in blue are input cells, while all numbers in bold are the results that flow through to the decision tree.

S. Cowden Field	
Drill Cost:	$1,250,000
Outperform NPV:	**$9,767,154**
Match NPV:	**$6,942,754**
Underperform NPV:	**$2,657,720**
Dry Hole NPV:	**$1,696,895**

Infill Drill - Match Projections

Years	# Wells (cum)	BPD Inc./Well*
0	0	0
1	1	30
2	3	25
3	5	18
4	7	12
5	8	10

*Avg. per year

Infill Drill - Underperform Projections

Years	# Wells (cum)	BPD Inc./Well*
0	0	0
1	1	20
2	3	10
3	3	7
4	3	5
5	3	5

*Avg. per year

Infill Drill - Outperform Projections

Years	# Wells (cum)	BPD Inc./Well*
0	0	0
1	1	45
2	3	30
3	5	20
4	7	15
5	8	10

*Avg. per year

Infill Drill - Dry Hole Projections

Years	# Wells (cum)	BPD Inc./Well*
0	0	0
1	1	0
2	2	0
3	2	0
4	2	0
5	2	0

*Avg. per year

Figure 34. Infill Drilling Costs and Production Projections

This table is followed by a graph that shows the production increases for each possible outcome as compared to the base case production curve (see Figure 35).

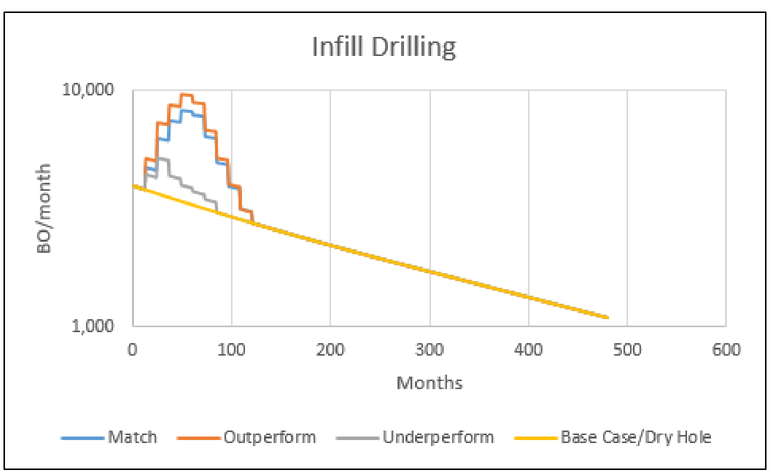


Figure 35. Infill Drilling Production Graph

Figure 36 shows the fifth and final branch on the decision tree that covers all possible outcomes for infill drilling.

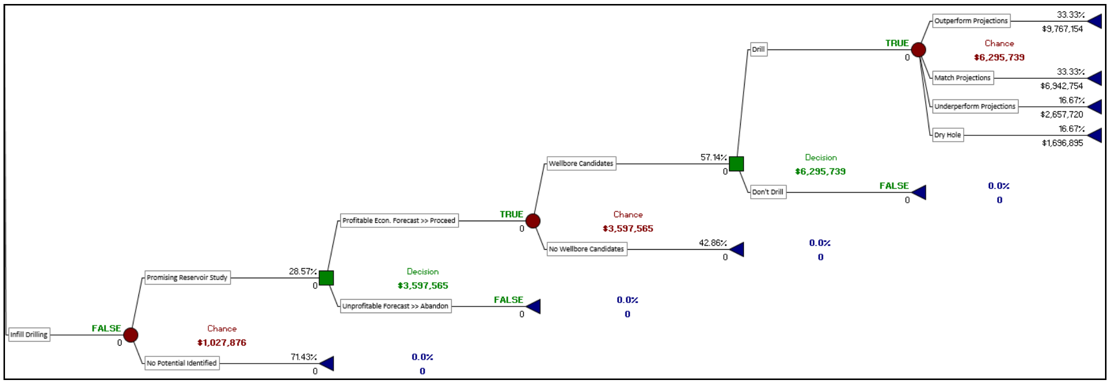


Figure 36. Infill Drilling Decision Tree

5. RESULTS

The results of the Green Tree model for the South Cowden field are generated from the inputs shown in the preceding Section 4, which uses best estimates for costs, probabilities, and production responses from the S. Cowden field. Results vary greatly depending upon commodity price scenarios as well as many of the intervention inputs, all of which will be discussed in the following sections.

5.1 Sensitivity Analysis

Perhaps the most important user input in the Green Tree model is the starting commodity price and accompanying price forecasts. As previously discussed, any starting price can be input for oil, gas, and NGLs, and there are currently three different price forecasts for each commodity to choose from. These pricing scenarios will not only affect the base case value of the field, but will also affect the commodity prices applied to the production forecasts for each intervention (as discussed in Section 4). In order to show these effects, a sensitivity analysis to commodity price was conducted with three different starting prices for oil and gas, with each of the three projected commodity prices being applied to the three price scenarios (see Figure 37), resulting in a total of nine price scenarios. While the model allows the user to use any possible pricing scenario, these nine scenarios were chosen to display a concise view of the effects of commodity prices on the model results.

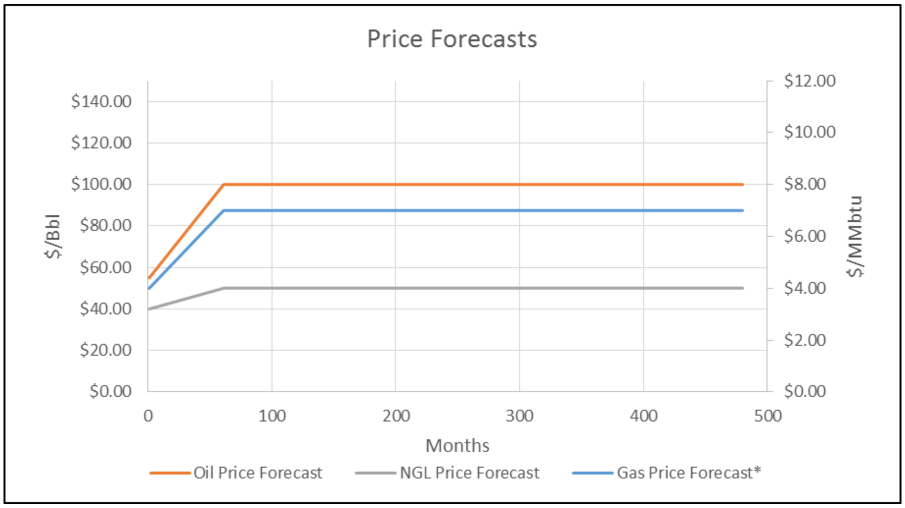


Figure 37. Commodity Price Projections Used

All nine price scenarios as well as projected outcome generated by the model can be found in Table 2 below. As designed, the optimal intervention varies based upon which base price and future price scenario is selected.

Inputs:				Outputs:			
Starting Oil Price: ($/STB)	Starting Gas Price: ($/Mmbtu)	Oil Forecast: (5yr target)	Gas Forecast: (5yr target)	Base Case PV10:	Optimal Intervention:	Total EMV w/ Optimal Intervention:	Optimal Intervention EMV:
$45.00	$3.00	$75.00	$5.00	-$63,758	Reservoir Stimulation > Frac	$3,787,182	$3,850,940
$45.00	$3.00	$100.00	$7.00	$3,834,856	LOE Reductions	$6,881,298	$3,046,442
$45.00	$3.00	$125.00	$9.00	$8,104,181	LOE Reductions	$11,576,465	$3,472,284
$55.00	$4.00	$75.00	$5.00	$766,903	Reservoir Stimulation > Frac	$4,391,931	$3,625,028
$55.00	$4.00	$100.00	$7.00	$4,540,564	LOE Reductions	$7,655,598	$3,115,034
$55.00	$4.00	$125.00	$9.00	$8,797,380	LOE Reductions	$12,292,812	$3,495,432
$65.00	$5.00	$75.00	$5.00	$1,454,158	Reservoir Stimulation > Frac	$4,972,640	$3,518,482
$65.00	$5.00	$100.00	$7.00	$5,227,849	LOE Reductions	$8,342,883	$3,115,034
$65.00	$5.00	$125.00	$9.00	$9,484,665	LOE Reductions	$12,980,097	$3,495,432

Table 2. Optimal Intervention Results for Each Price Scenario

The first outputs column shows the PV10 value of reserves that is generated by the decline curve and the economic inputs the user has selected (see Figure 12). This is called the “base case” PV10 because this is the most conservative value for the field as it assumes no interventions are implemented. The second outputs column on Table 2 shows the optimal intervention selected by the decision tree based off of the highest EMV value. The third outputs column displays the total EMV value of the field with the optimal intervention, and the last column shows the total field EMV minus the base case EMV, thus showing the upside EMV provided by the optimal intervention.

A sensitivity analysis for the Base Case PV10 values can be seen in Figure 38, which shows the effect on the base case PV10 value for each starting price at all of the five year price targets. This graph shows the fairly linear effects of starting price and price forecasts on the value of this field.

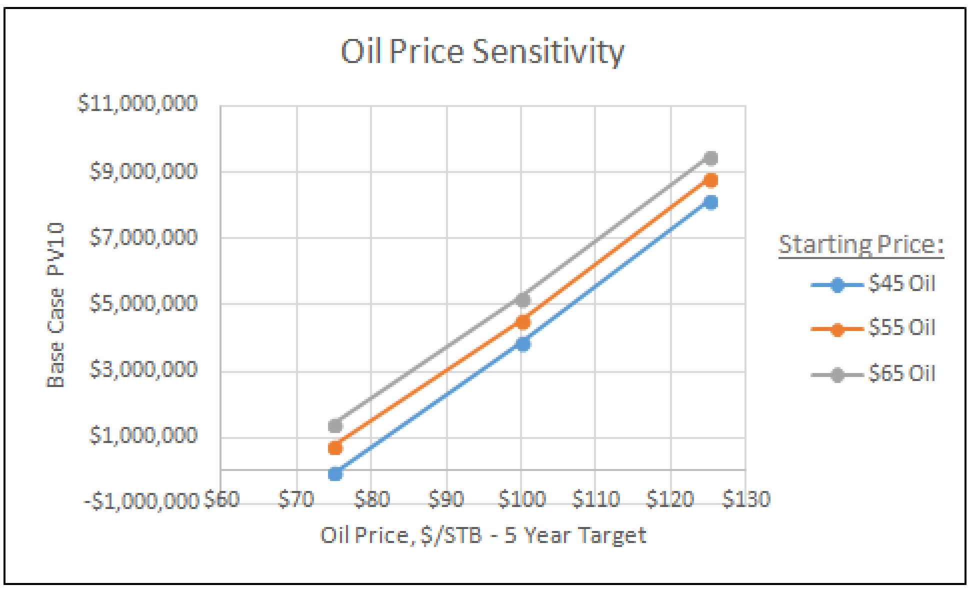


Figure 38. PV10 Results for Various Starting Oil Prices

The cumulative total cash flow under each of the five intervention scenarios can be seen in Figure 39. This table shows that cash flows for many of the interventions overlap for the first few years, but by the third or fourth year they each begin to differentiate themselves.

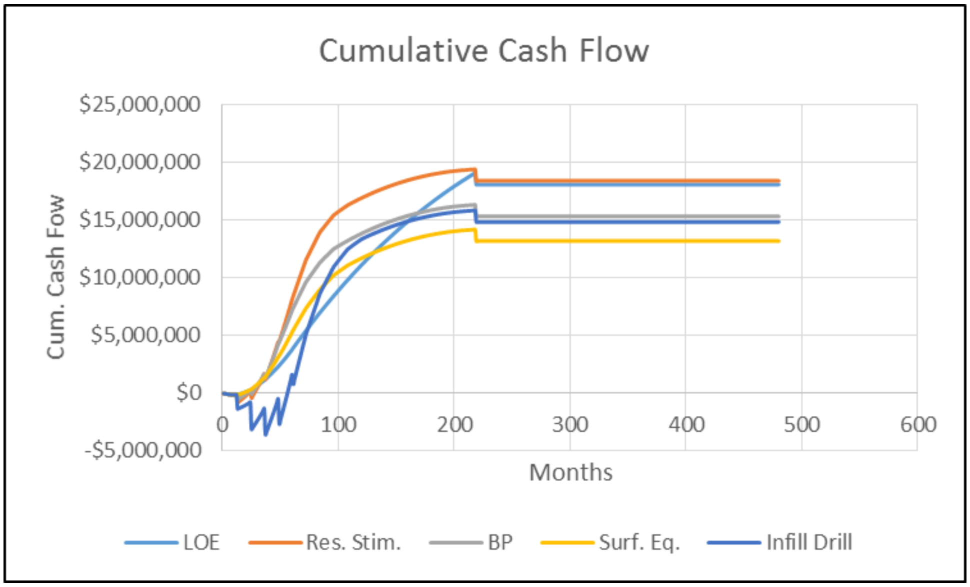


Figure 39. Cumulative Cash Flow Projections for Each Intervention ($45-$100)

The sharp changes in cumulative cash flow values during the first few years for Infill Drilling are due to the large expense of drilling a new well. Also, while the cumulative cash flow lines for each intervention appear to form a similar shape, the line for LOE does not match the others as it appears to be fairly linear. LOE reductions are calculated as a percent reduction in OPEX, while all other interventions use short term increases in production to counter their capital expenditure. Effects of this calculation method for LOE Reduction can also be seen in Figure 40. EMVs for all interventions except for LOE increase in a linear fashion as starting oil price increases in this graph.

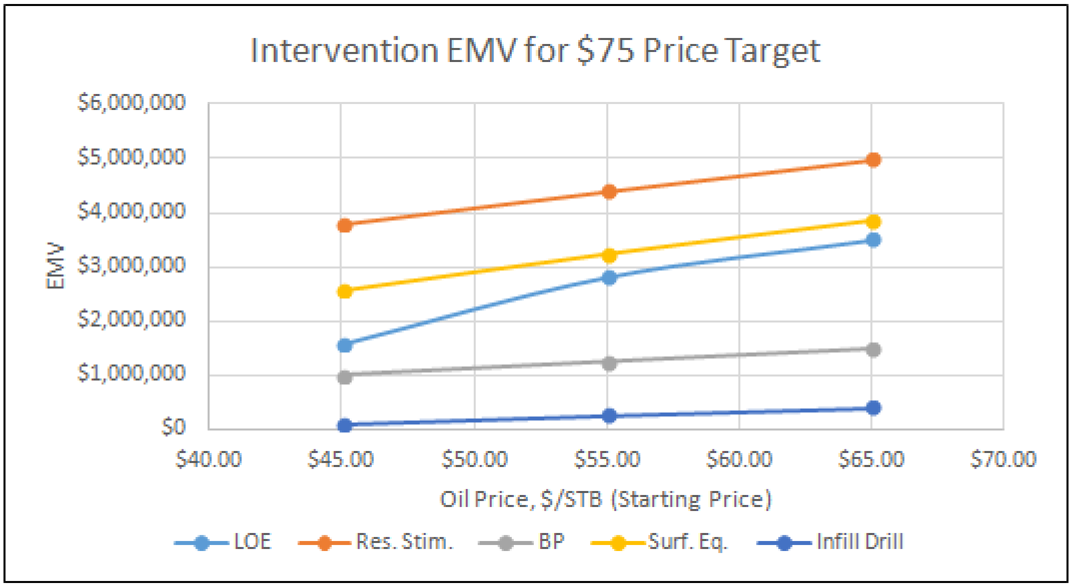


Figure 40. EMV for Each Intervention for All Starting Prices ($75/bbl Target)

The bend in the LOE curve is due the effects of the percentage decrease in OPEX over time. While all other interventions involve spending CAPEX to achieve a set increase in production per well, LOE Reductions only affects operating expenses on a percentage basis.

5.2 Prioritizing Interventions

It should be noted that LOE Reduction is the optimal intervention for the higher price forecasts of $100/bbl and $125/bbl, as seen in Table 2. Since the model does not weigh the cost of capital for each intervention but only the outcome's effect on total EMV, it does not properly categorize LOE Reductions. It is a reasonable assumption that all operators will be working to reduce LOE, regardless of intervention activity, as LOE reduction requires no capital deployment. An example of this decrease in monthly OPEX over a five year period for a "Large" LOE Reduction (see Figure 16) can be seen below in Figure 41. This data uses a $45/bbl starting price for oil and a $100/bbl oil price forecast after five years. A simple percentage reduction in OPEX for each of the first five years the field is owned is applied at the beginning of each year.

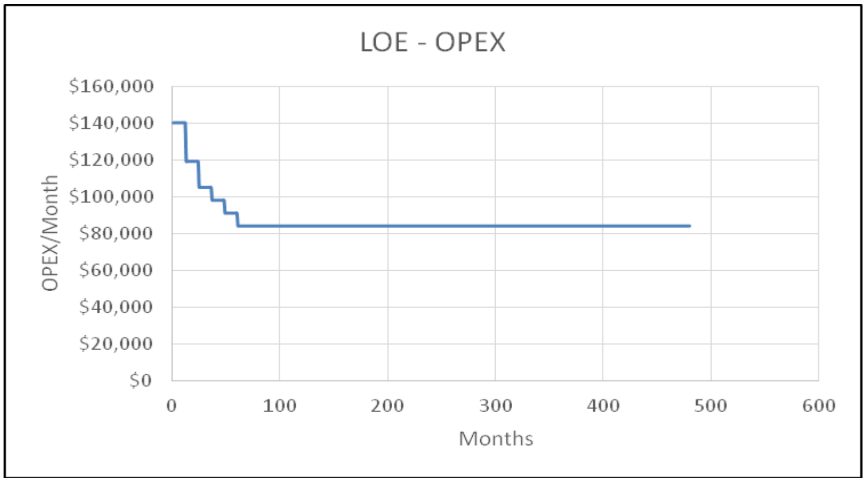


Figure 41. "Large" Monthly LOE Reduction Forecast

Figure 42 shows the cumulative CAPEX spent for each intervention over the forecasted 40 year period. The results shown in this chart are also from the “match” category of projected results, as seen for each intervention in Section 4 (each intervention has a projected production increase that “matches” projections, “underperforms” projections, and “outperforms” projections). The commodity price used for each intervention in this graph is a starting oil price of $45/bbl and a $100/bbl forecast after 5 years, as previously used.

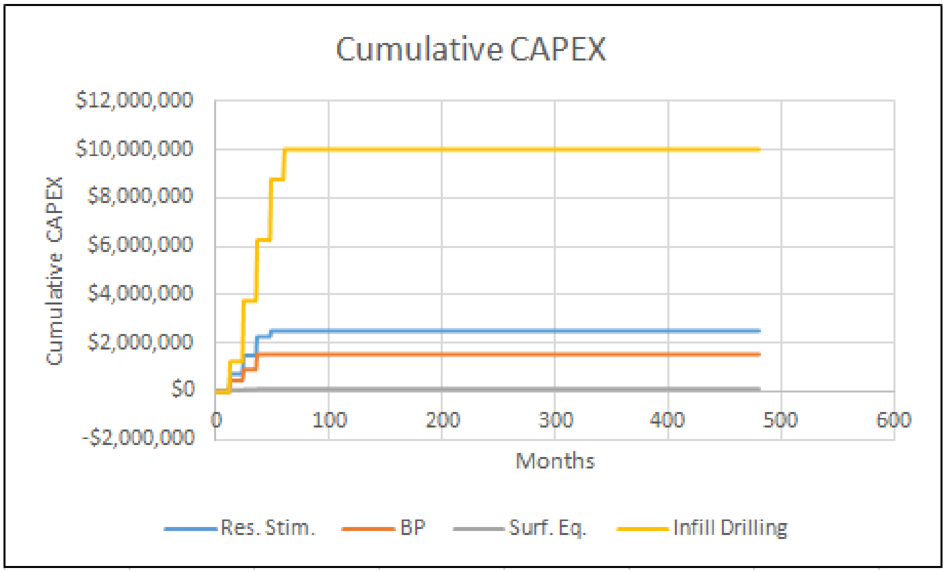


Figure 42. Cumulative Capital Deployed For Each Intervention

Infill drilling is by far the most expensive intervention, while making changes to surface equipment, such as pump size upgrades, is the least expensive option. The stair step manner in which CAPEX increases on the graph is due to the number of well implementations scheduled for each year on the inputs tab for each intervention.

The primary purpose of including LOE Reductions as an intervention is in helping an operator evaluate the chances and value of LOE reductions on a potential acquisition. Due to these facts, a second table was generated (Table 3) that showed the optimal intervention at each pricing scenario, but did not include LOE Reductions, thus the second best option was selected when LOE Reductions was the optimal intervention.

Inputs:				Outputs:			
Starting Oil Price: ($/STB)	Starting Gas Price: ($/Mmbtu)	Oil Forecast: (5yr target)	Gas Forecast: (5yr target)	Base Case PV10:	Optimal Intervention:	Total EMV w/ Optimal Intervention:	Optimal Intervention EMV:
$45.00	$3.00	$75.00	$5.00	-$63,758	Reservoir Stimulation > Frac	$3,787,182	$3,850,940
$45.00	$3.00	$100.00	$7.00	$3,834,856	Reservoir Stimulation > Frac	$6,729,552	$2,894,696
$45.00	$3.00	$125.00	$9.00	$8,104,181	Surface Equipment > Pump Size	$10,075,954	$1,971,773
$55.00	$4.00	$75.00	$5.00	$766,903	Reservoir Stimulation > Frac	$4,391,931	$3,625,028
$55.00	$4.00	$100.00	$7.00	$4,540,564	Reservoir Stimulation > Frac	$7,318,638	$2,778,074
$55.00	$4.00	$125.00	$9.00	$8,797,380	Surface Equipment > Pump Size	$10,687,972	$1,890,592
$65.00	$5.00	$75.00	$5.00	$1,454,158	Reservoir Stimulation > Frac	$4,972,640	$3,518,482
$65.00	$5.00	$100.00	$7.00	$5,227,849	Reservoir Stimulation > Frac	$7,899,377	$2,671,528
$65.00	$5.00	$125.00	$9.00	$9,484,665	Surface Equipment > Pump Size	$11,295,645	$1,810,980

Table 3. Intervention Results Without LOE

Once LOE Reductions have been replaced by the intervention with the second highest EMV, Reservoir Stimulation (Frac) replaces LOE for the $100/bbl forecast and Surface Equipment (upgrade pump size) replaces LOE for the $125/bbl forecast. These results reveal that the optimal intervention has a stronger correlation to the price forecast than to the starting commodity price. This is confirmed in Table 4 below as the results from the $45/bbl, $55/bbl, and $65/bbl starting oil prices all match this table as they all have the same results for each price forecast. The changes in optimal intervention that occur at each of the three forecasted oil prices are shown in this table and they hold the same order regardless of the starting oil price.

	Scenario 1 - $75 Price Target	Scenario 2 - $100 Price Target	Scenario 3 - $125 Price Target
1st Choice	Res Stim	LOE	LOE
2nd Choice	Surf Eq	Res Stim	Surf Eq.
3rd Choice	LOE	Surf Eq.	Res Stim.
4th Choice	BP	BP	BP
5th Choice	Infill	Infill	Infill

Table 4. Intervention Priority (Left Column) Based on Price Scenarios

EMV totals for each intervention at each of the nine price scenarios can be found in Table 5Table 5. Total EMV Results for All Interventions, from which Table 4 was created. The EMVs for the top three interventions can be seen to be very close, while the last two choices of Behind Pipe Potential and Infill Drilling lag significantly behind the first three choices. The optimal intervention choice is shown with red text and the secondary choice is shown in blue text. With this text coloring the reader can observe that the same optimal intervention pattern is followed for each of the three starting oil prices.

Inputs:				Total EMV For Each Intervention				
Starting Oil Price: ($/STB)	Starting Gas Price: ($/Mmbtu)	Oil Forecast: (5yr target)	Gas Forecast: (5yr target)	LOE	Res Stim	Behind Pipe	Surf. Eq.	Infill
$45.00	$3.00	$75.00	$5.00	$1,568,744	$3,787,182	$990,391	$2,574,699	$80,389
$45.00	$3.00	$100.00	$7.00	$6,881,298	$6,729,552	$2,258,081	$6,166,703	$1,027,876
$45.00	$3.00	$125.00	$9.00	$11,576,465	$9,880,835	$3,639,003	$10,075,954	$2,038,207
$55.00	$4.00	$75.00	$5.00	$2,811,632	$4,391,931	$1,239,493	$3,241,430	$246,710
$55.00	$4.00	$100.00	$7.00	$7,655,598	$7,318,638	$2,499,025	$6,787,911	$1,176,736
$55.00	$4.00	$125.00	$9.00	$12,292,812	$10,464,253	$3,876,885	$10,687,972	$2,185,025
$65.00	$5.00	$75.00	$5.00	$3,498,886	$4,972,640	$1,475,914	$3,849,073	$392,555
$65.00	$5.00	$100.00	$7.00	$8,342,883	$7,899,377	$2,735,459	$7,395,584	$1,322,588
$65.00	$5.00	$125.00	$9.00	$12,980,097	$11,044,992	$4,113,318	$11,295,645	$2,330,877

Table 5. Total EMV Results for All Interventions

All EMVs used in this table come from the decision tree and provide the user a clear order for interventions in the field. The primary reason the behind pipe and infill drilling interventions find themselves as the last intervention choices is their high cost, accompanied by a production forecast that is only slightly greater than that for Reservoir Stimulation or Surface Equipment upgrades. Meaning that an operator would only pursue these interventions if they have already exhausted all opportunities for reservoir stimulation and surface equipment upgrades, or if they forecast significantly greater production increases from each of these interventions. Otherwise, it appears that the returns for Infill Drilling and Behind Pipe Potential fall significantly behind Reservoir Stimulation and Surface Equipment Upgrades.

5.3 Multiple Options Selected to Calculate Acquisition Price

If an operator were to use this model to evaluate an acquisition, they could accumulate EMVs for multiple interventions to determine a realistic total upside value. While the results would be greatly reliant upon the operator's discretion in summation of these EMVs, this tool can add significant value for this purpose. In order to show an example of this, Table 6 has been prepared.

Base Case PV10:	**$4,540,564**		
	Total EMV	Intervention EMV	Positive EMVs
LOE	$7,655,598	$3,115,034	$3,115,034
Res Stim	$7,318,638	$2,778,074	$2,778,074
Behind Pipe	$2,499,025	-$2,041,539	$0
Surf. Eq.	$6,787,911	$2,247,347	$2,247,347
Infill Drill	$1,176,736	-$3,363,828	$0
		Total Upside:	$8,140,455
		Discount Factor:	15%
		Total Adj. Upside:	**$6,105,341**

Table 6. Upside Valuation for Acquisition

All values in this table were calculated for a starting oil price of $55/bbl and a five year target of $100/bbl. At the top of the table is the base case PV10 value for this price scenario as can be found in Table 3 above. The column titled "Total EMV" shows the EMV for the entire field calculated by the model for each intervention, also found in

Table 5 above. The next column to the right titled, “Intervention EMV” shows the total EMV for each intervention minus the base case PV10 value, to provide the upside value of each intervention. Under this pricing scenario, Behind Pipe and Infill Drilling interventions actually lose money for the company, while the other three interventions add value to the field. For this reason, the last column shows the upside EMVs which are positive, eliminating those with negative values. These positive upside EMVs are summed in the “Total Upside” line, and then an additional discount factor of 15% is applied by the company to produce a total adjusted upside value of $6,105,341. This value will then be added to the base case PV10, for a total field value of **$10,645,905**. This shows a simple and easy way for a company to use this model to determine an adequate acquisition price that includes risk adjusted upside from successful interventions. As previously stated, many operators will develop different methods of calculating this, as they may use a different discount factor, or may adjust the intervention inputs so that all possible interventions result in positive additions to base case PV10 values.

5.4 Effect of Posterior Probabilities

It is also possible for a company to update the probabilities and projections used for each intervention in real time as they receive results from the field. As probabilities, prices, and production forecasts are adjusted, this will have an effect on the optimal intervention determined by the decision tree as well as the EMV upside assigned to each intervention. The model is created to be updated in real time as interventions are conducted, with the goal of refining the projections to ensure greater accuracy over time.

Depending on the size of the field, the operator will have a limited number of wellbores in which to conduct workovers. Thus, once wellbore options for the optimal intervention have been exhausted, the operator can place a zero value for that intervention in the inputs page so that the tree will then select the next optimal intervention. Once opportunities for the second intervention have been exhausted, then the third will be implemented, and so on and so forth until no more interventions remain and the company must consider divesting the field.

5.5 Divestment Decisions

When seeking to optimize a portfolio of marginal fields, an operator will seek to determine the optimal time for a divestment decision. While many timing factors are outside of an operator’s control, such as commodity prices, the success of offset operations, and current market conditions, there are several aspects of divestment timing that the operator can control. The Green Tree model can help an operator evaluate optimal divestment timing by determining remaining recoverable reserves in the field, remaining EMV from interventions, and determine a divestment price that will meet the operator’s IRR threshold. Once the operator has determined the desired IRR for a given marginal field, the Green Tree model can be updated periodically to determine if the IRR threshold has been achieved. The operator will need to use historic production performance in the field along with an estimated divestment price provided by updating the Green Tree model in order to determine if their IRR hurdle rate has been met. Updating the model will follow the same pattern as explained in section 4, first a decline curve will be built that provides a base case PV10 value, then the operator will update each intervention inputs tab with the most current field data and results. If some interventions have been exhausted, the user will input a zero value for EMV, while other interventions can be updated based upon remaining wellbore options for that intervention. For example, in the S. Cowden field six wells have been re-fractured to date, but ten wellbore candidates remain for re-fracturing, thus the results from the first six wells would be used to calculate the expected production increases and probabilities, while the remaining ten wells would be used to calculate remaining EMV upside for the re-fracturing intervention. This process will continue for all the remaining interventions in the field, including the percent reduction in LOE achieved to date. The user could then sum all positive intervention EMVs remaining in the field with the base case PV10 value to determine an adequate divestment price, as seen in Section 5.3, in order to determine if the IRR threshold has been met. Discretion would then be used by the operator to determine optimal divestment timing, contingent upon expected returns from the remaining interventions. The operator will either determine that possible upside in the field remains an attractive investment and continue to pursue interventions, or that the current divestment price is more attractive than continuing to pursue interventions and will look to sell the field.

6. DISCUSSION

6.1 Green Tree Strengths

The Green Tree Model has the potential to be used for a myriad of upstream field development applications relating to decision making about property acquisition and divestment, as well as intervention evaluation in legacy oil fields. Many of the smaller companies who operate these legacy assets currently use fairly unsophisticated means to evaluate property upside value and production enhancement options in potential acquisitions. Most companies will depend on the previous experience of their engineers to determine possible upside options when evaluating an acquisitions. The engineer will hold a brief discussion with the current operator and/or those representing the seller, as well as conduct a quick review of the provided sale data, which often includes reserves information and a few wellbore files. Using this limited knowledge, the engineer will then estimate costs and projected returns for each intervention, and often using a petroleum economics software such as Landmark's Aries, to show the effect on total field reserves. At times, evaluations for small assets are even less technical than this approach, as operators will use back of the envelope calculations that are based on an operator's guess for each intervention's success. Thus, one of the greatest values the Green Tree model provides is to clearly show the risk adjusted values for each intervention and provide the operator a quick and concise way to make decisions that otherwise would be far too complicated for a simple mental math analysis. Because this model uses an iterative process to give better clarity on the value and probability of success for each intervention, it will help the operator to develop a systematic decision making process that provides the most accurate projections possible. The strength of this model is its simplicity and adaptability, as all calculations are straightforward and its design in Microsoft Excel allows it to be easily adapted to fit any legacy oil field.

6.2 Implementation Requirements and Future Work

It is essential that companies who plan to use the Green Tree model create a data bank of past results in order to improve the probabilities and production projections used in this model. While its structure is basic, opportunities for future improvement exist, such as adding price projection options that increase exponentially over a period greater than five years. Each company will hold a unique view of commodity price forecasts, and thus they should be able to adjust the model to accurately match their forecasts. The model could also be improved by implementing the CAPEX and production increases from interventions on a monthly basis, as opposed to a year basis. The period of their effect on the field value could be extended to last longer than five years. Perhaps a more significant change to the model could come in considering re-structuring the tree so that LOE is considered to be a continuous improvement and not a onetime intervention option. As we learned in the results, it is not accurate to ever have LOE selected as the primary intervention since it requires no capital to complete and all operators will continually be focused on LOE reduction. Also, LOE reductions are calculated differently than the other four interventions as LOE reductions only affect OPEX on a percentage reduction basis. The primary purpose of including LOE Reductions in the model is to help provide a reasonable expectation for an operator of possible reductions to LOE based on past success in similar fields. This comes into play largely when an operator is evaluating an acquisition.

6.3 Comparison With Other Methods to Assess Asset Value

Many different techniques exist to determine the value of an oil and gas property. In the “Economic Evaluation of Oil and Gas Properties Handbook”, published by the U.S. Bureau of Land Management, two primary methods are used when valuing an oil and gas properties: (1) comparable sales approach and (2) the income approach. The comparable sales approach uses the sales price valuation of a comparable property to place a value on the asset being evaluated (BLM, 2015). An example of this would be a per acre lease price or a per barrel purchase price for a property with proved reserves. While this approach is valuable and commonly used, the Green Tree model does not use any comparable sales information in its valuation. The income approach typically uses a discounted cash flow model to determine the present value of the projected cash flows from the asset (BLM, 2015). Companies will often create a discounted cash flow model for an asset based upon its proved reserves and then compare this value to the valuation for other comparable assets, thus using a combination of both valuation methods.

Other, more simplistic methods exist, such as “the 3x rule”, which multiplies an asset’s 12 month cash flow by three, in order to determine a fair market value (BDO, 2011). This is one of the oldest and simplest methods for valuing oil and gas properties, as is often used by CPAs and attorneys to value estates and gift tax returns (BDO, 2011). While this method is simple, it has proven to grossly under estimate the value of oil and gas assets compared to their actual selling prices (BDO, 2011). This method neglects all geologic data, historic production, comparable sales prices, and upside value in an asset, and cannot provide the seller any confidence. An operator must spend the effort and expense to accurately assess the value of a property through engineering analysis and comparable sales prices from other assets. Many of the recent advances in reserves and economics software has made this method of valuation largely obsolete and thus it is not recommended.

While the aforementioned combination of the income approach and the comparable sales approach are the most commonly used for valuation of oil and gas properties, marginal properties differentiate themselves in several ways. First, marginal properties are highly sensitive to commodity prices and operating conditions. They typically operate on older equipment that is much more likely to fail than newer equipment, and at such low production volumes even a few days of lost production can make the wells uneconomic. Secondly, marginal properties are very sensitive to wellbore interventions targeting increased production, which, if successful, can lead to a doubling of a wells daily production. The discounted cash flows (DCF) method relies on an engineer generating a decline curve that forecasts production for the asset, preferably on a well by well basis. This method works well in areas currently under development where a reliable type curve is available and/or the wells are in the early part of their decline. These wells will follow a predictable and steady decline, with very few expected interferences. Marginal wells on the other hand typically have a fairly flat decline and their future production is highly dependent upon which interventions are implemented.

Thus, it is crucial for a marginal well operators to properly assess the risk adjusted upside of interventions.

For these reasons the Green Tree model provides a different approach to valuation for marginal assets than for assets that are earlier in their development lifecycle. A commonly used framework does not exist for determining a PV10 value along with a risk adjusted value for upside interventions in marginal oil fields, thus the Green Tree model was created to fill this gap. Operators who frequently purchase and sell marginal assets will typically use their past experience and intuition to place an upside valuation on a marginal property. While this approach is useful, it does not account for the risk of each intervention based on historic operating data as done by the Green Tree model. It also does not have a clear and concise summary of the value of each intervention with a decision tree that automatically directs the operator towards the intervention with the highest calculated EMV. The Green Tree model does not suggest an entirely new way of approaching these assets, but does provide a much more accurate, clear, and concise valuation and decision making tool for marginal assets.

7. CONCLUSIONS AND RECOMMENDATIONS

The Green Tree model is designed to help operators of marginal assets maximize their asset value by allocating their capital towards the best well workover options, prioritizing field intervention decisions, and placing an accurate value on the acquisition or divestiture of an asset. Marginal wells hold tremendous value as they have produced 2.85 billion barrels of oil and 19.9 Mcf of natural gas over the past ten years, adding over $300 billion in production value to the U.S. economy (IOGCC, 2015). While they made up nearly 8% of total U.S. oil and gas production in 2015, they are frequently neglected by operators, leading to a noted absence of new work seeking to improve the operation and valuation of these assets (IOGCC, 2015). This model was structured after a marginal field in the Permian basin and uses the inputs from five separate field interventions to determine the optimal intervention path as well as a total asset value. It relies heavily upon user inputs for probabilities and projected production increases from each of the interventions. After the model was completed, it was tested and validated with field data from the same Permian field used to build its structure. Assuming accuracy of input data, the results showed that it is possible to use a decision tree to determine the optimal intervention at any point in time for a marginal oil field. The decision tree will show the intervention with the highest EMV, directing the operator to pursue this intervention until all wellbore candidates are exhausted and then moving to the intervention with the second highest EMV. While it is likely that an operator will pursue multiple interventions simultaneously, this tree helps place likely outcome values on each one in order to help operators make better decisions. The results also showed that operators can lose significant value if they are not properly assessing the upside value in an acquisition or divestment decision. The model cannot only be used to create an acquisition price, based on the PV10 base case value along with a summation of the upside EMVs, but can also be used to analyze optimal divestment timing in a field once an IRR hurdle rate has been met. Lastly, the results revealed that LOE Reductions should be treated as a continuous improvement in the field and thus should not be selected as the optimal intervention. Whenever LOE Reduction has the highest EMV then the intervention with the second highest EMV should be chosen. LOE Reduction is also unique in that it requires no capital to implement and the model calculates its effect on cash flows based as a percentage reduction in OPEX, as opposed to a set increase in per well production for the other four interventions.

As previously mentioned there are three primary decisions the model can be used for: (1) Acquisition price, (2) Value and timing of field interventions, and (3) divestment timing and expected minimum sales price. The results section used the S. Cowden data to verify that the model can produce accurate estimates for each of these three decisions/valuations. While the model does aid operators in evaluating each of these decisions, improvements to the model can still be made. More advanced price forecasts as well as inputs that affect cash flow on monthly instead of a yearly basis would help provide more accurate results. It would also help if the tool automatically assumed LOE reductions were taking place and thus selected an optimal intervention without LOE reductions being considered as an option. Lastly, the model does not account for market conditions when evaluating an acquisition or divestment, thus the user must factor many other outside factors when making a decision apart from the decisions suggested by the model.

Operators with large data banks of historical results of wellbore workovers in marginal oil fields will greatly increase their ability to generate an accurate forecast from this model. Successful use of the Green Tree model is dependent on the quality of the inputs provided by the user. Small changes to probabilities or production responses to interventions will lead to large changes in the EMV for each intervention, so an operator must insure that he is using the most accurate input data possible. It is also important for a user to apply an adequate discount factor or any acquisition price created from a summation of intervention EMVs. Lastly, the operator should always run a sensitivity analysis to price for the given asset as commodity price has proven to be very unpredictable. This sensitivity analysis will aid an operator in determining the required range of product prices required to make an acquisition profitable.

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APPENDIX

Stripper Well Data

According to EIA data, the United States has been the world's largest producer of oil and gas since 2012 when it took the top spot from Russia (see Figure 43).

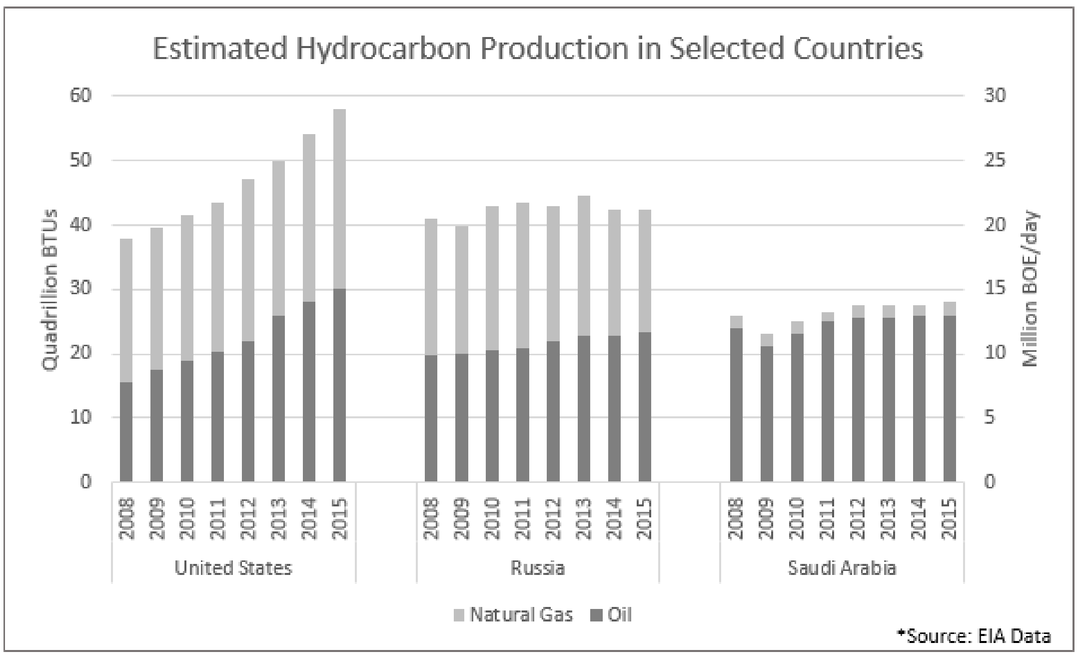

Figure 43. Estimated Petroleum and Natural Gas Production in Selected Countries

A significant energy boom has occurred in the U.S. over the past ten years, in large part due to the widespread development of unconventional resources. This boom has decreased dependence on oil imports and reversed the decade's long downward trend in domestic oil and gas production. This boom has also dampened the impact of marginal wells as they accounted for 17% of total oil and gas production in 2008, but only 10% of total production in 2015 (EIA, 2015). While the production share from marginal wells has dropped over the last ten years, these wells continue to play a significant role in the hydrocarbon production of the U.S.

It is important to note that the EIA defines a stripper or marginal well as “an oil well producing no more than 15 barrels of oil equivalent per day over a 12 month period or a gas well producing no more than 90,000 cubic feet per day over a 12-month period” (EIA, 2015). This differs slightly from the definition of a marginal well provided by the IOGCC, which defines a marginal oil was as producing equal to or less than 10 bbls of oil per day on a monthly average. Thus, the EIA statistics for stripper wells will include a greater number of oil and gas wells than the IOGCC figures for marginal wells. It is also important to note that the IOGCC does not use the terms “marginal” and “stripper” synonymously. A stripper well, is “an oil well whose maximum daily average oil production does not exceed 10bbls per day during any consecutive 12 month period” (IOGCC, 2015, p. 3). The IOGCC 2015 Marginal Well Reports states that 69.1% of all operated oil wells and 75.9% of all operated gas wells were labeled marginal in 2015, resulting in 72.2% of all operated wells in the U.S. claiming marginal status. EIA data also shows that stripper wells have grown significantly over the past ten years, particularly in the number of stripper natural gas wells. Based on these trends, as well as the increased drilling of unconventional wells, it is anticipated that the number of wells listed as marginal and/or stripper will continue to increase in the future. (Figure 44 and Figure 45 come from EIA data for stripper wells.)

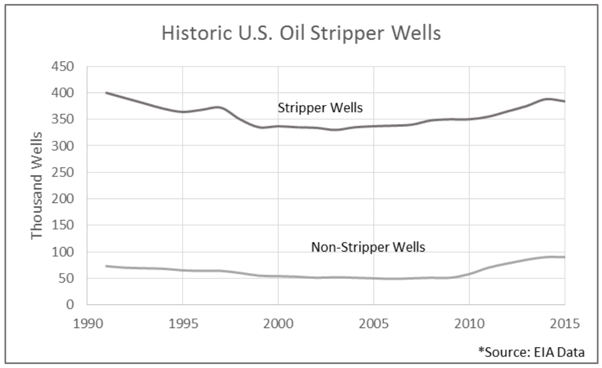

Figure 44. Historic U.S. Well Count for Stripper Oil Wells

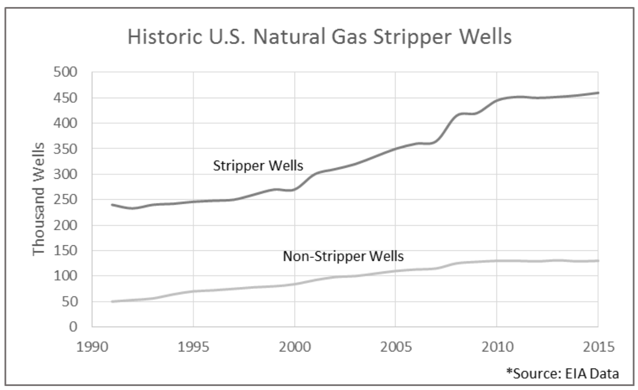

Figure 45. Historic U.S. Well Count of Stripper Gas Wells

The IOGCC 2015 Marginal Well Report also estimates that marginal wells have produced 2.85 billion barrels of oil and 19.9 billion MCF of natural gas over the past ten years, contributing over $300 billion to the economy for their production. Total production from these marginal assets accounted for 8.5% of oil production and 7.0% of gas production in 2015, which is down significantly from a peak in 2008 (IOGCC, 2015). Total hydrocarbon production from marginal wells has increased over the past 10 years, but their share of total production has been diminished due to the prolific production from unconventional wells (see Figure 46 and Figure 47).

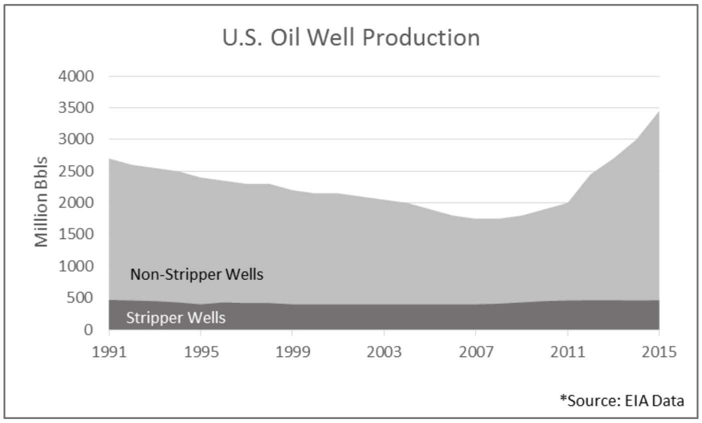

Figure 46. Historic U.S. Oil Production from Stripper and Non-Stripper Wells

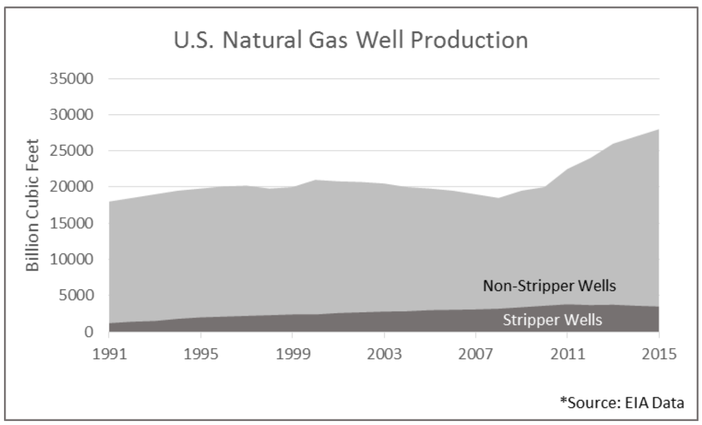

Figure 47. Historic U.S. Gas Production from Stripper and Non-Stripper Wells

Prematurely plugging and abandoning these marginal assets during a dip in commodity prices would be a grave mistake as they have proven to hold immense value over long periods of time. Not only do many of these wells hold meaningful quantities of recoverable reserves, some of which are yet to be exploited through wellbore interventions, but they also hold valuable infrastructure for the future development of new formations and/or unconventional activity (IOGCC, 2015). Many of these overlooked assets could hold major economic value for the current operators or for a company looking to acquire and exploit such assets.